University of Alberta

A Depletion Strategy for Oil Production with a Secondary Recovery Option

by

Mustafa Oguztoreli ©

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fulfilment of the requirements for the degree of

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The undersigned certify that they have read, and recommend to the Faculty of Graduate Studies and Research for acceptance, a thesis entitled A Depletion Strategy for Oil Production with a Secondary Recovery Option submitted by Mustafa Oguztoreli in partial fulfilment of the requirements for the degree of Doctor of Philosophy in Engineering Management.

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To my mother Ceyda
and to the memory of my beloved sister Billur

Abstract

An oilfield usually has a secondary recovery stage for economically viable oil production over its producing life. The total inventory of recoverable oil will depend on the manner in which the reservoir is produced. The initiation of a secondary recovery stage at different times over the primary production life cycle may result in different ultimate recoveries. This work supplements a theoretical development for constructing optional-stage depletion strategies with a realistic application to the Chedderville Viking "A" Pool in Alberta. The particular field produces naturally under solution gas drive and is a good candidate for a pattern waterflood. Ultimate recovery and project economics depend on the depletion strategy that manages both natural depletion under primary production and pattern waterflooding under secondary recovery.

The reservoir is characterized with a black oil simulation model calibrated by matching historical production and pressure data. Primary operations adhere to regulatory constraints that limit monthly allowables for oil and gas production. A pattern waterflood is proposed and control policies established to meet design objectives. Secondary waterflood branches are forecast along a primary depletion path. A branched differential decision process using dynamic programming techniques is used to find investment and operating decision rules that maximize the modelled economic value of remaining operating alternatives over a strategic window.

The strategic model system examines the waterflood investment timing option. Nested primary and secondary operational modes for controlled production, suspended field-wide operations and early abandonment are also examined. The space of allowable operating pathways give considerable flexibility for decision making. The value of alternative recovery options depends on reservoir depletion paths and the probability structure of macro-economic scenarios. The analysis is restricted to situations where the macroeconomic oil price and cumulative oil production are sufficient state variables for decision-making. Oil price expectations assume an exogenous continuous random walk in volatile future price movements. An intertemporal equilibrium asset valuation model, based on oil futures price dynamics, is used to value production cash flows from alternative recovery paths in terms of macro-economic factors and field-specific costs. Uncertainty about future price gives a flexible decision process additional value over rigid production plans. The valuation method parallels derivative asset pricing models used in financial option analysis.

The model system depletion strategy is intended to guide oil producers to make better management decisions in their field operations. The strategy constitutes an optimal policy that is compiled as a schedule of price sensitive decision rules which apply at future depletion states, regardless of how the model operations were managed up to that point in time.

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Nomenclature

A_1	primary abandonment expense ($)
A_2	secondary abandonment expense ($)
A_g	Darcy gas transmissibility at the block boundaries
A_o	Darcy oil transmissibility at the block boundaries
A_w	Darcy water transmissibility at the block boundaries
B_g	gas formation volume factor (reservoir ft^3/scf)
B_o	oil formation volume factor (reservoir bbl/STB)
B_w	water formation volume factor (reservoir bbl/STB)
c	marginal net convenience yield rate per dollar unit of commodity held in inventory
c_t	total compressibility (psi^{-1})
c_r	rock compressibility (psi^{-1})
c_o	oil compressibility (psi^{-1})
c_w	water compressibility (psi^{-1})
c_g	gas compressibility (psi^{-1})
C	marginal net convenience yield
$\mathcal{C}_1$	active primary control policy
$\mathcal{C}_2$	active secondary waterflood control policy
$\mathcal{C}f$	before-tax cash flow ($/day)
dLN	lognormal probability density
dm	probability density measure for future price state
dY	instantaneous dollar return on the portfolio
$\mathcal{D}$	depletion strategy
$\mathbf{e}_x$	rectilinear coordinate unit vector in x-direction
$\mathbf{e}_y$	rectilinear coordinate unit vector in y-direction
$\mathbf{e}_z$	rectilinear coordinate unit vector in z-direction
f_1	primary fixed costs ($/day)
f_2	secondary fixed costs ($/day)
F	futures price
g	gravitational constant
GOR	base gas-oil ratio
$\overline{GOR}$	producing gas-oil ratio
h	effective completion interval thickness (ft)
k_{rg}	gas relative permeability
k_{rgro}	gas relative permeability in gas-oil at residual oil saturation
k_{ro}	oil relative permeability
k_{rog}	oil relative permeability in gas-oil system
k_{roiw}	oil relative permeability in water-oil at irreducible water saturation
k_{row}	oil relative permeability in water-oil system

k_{rw}	water relative permeability
k_{rwro}	water relative permeability in water-oil at residual oil saturation
K_{12}	lump sum waterflood capital cost ($)
K_x	absolute permeability (md) in x-direction maximum core permeability (md)
K_y	absolute permeability (md) in y-direction 90° core permeability (md)
K_z	absolute permeability (md) in z-direction vertical core permeability (md)
$\tilde{K}$	rock permeability tensor (md)
M_1	primary depletion state partition
M_2	secondary depletion state partition
MRL	base maximum rate limitation (STB/day)
Mscf	1000 scf
MSTB	1000 STB
MW	molecular weight (lbs/lb-mole)
n_g	saturation exponent for k_{rg}
n_{og}	saturation exponent for k_{rog}
n_{ow}	saturation exponent for k_{row}
n_w	saturation exponent for k_{rw}
$N_{Courant}$	Courant number
N_s	price state partition
N_x	reservoir grid partition in x-direction
N_y	reservoir grid partition in y-direction
N_z	reservoir grid partition in z-direction
R_{so}	gas-oil solubility (scf/STB)
R_{sw}	gas-water solubility (scf/STB)
p	reservoir fluid pressure (psia) grid block pressure (psia)
p_b	bubble point pressure (psia)
p_{cgo}	gas-oil capillary pressure (psia)
p_{cow}	oil-water capillary pressure (psia)
p_g	gas pressure (psia)
p_o	oil pressure (psia)
p_{pc}	pseudo-critical pressure (psia)
p_w	water pressure (psia)
p_{wf}	flowing bottomhole pressure (psia)
p_{wh}	well head pressure (psia)
p_{wf}^{min}	minimum oil production bottomhole pressure constraint (psia)
p_{wf}^{max}	maximum water injection bottomhole pressure constraint (psia)
Δp_f	friction loss pressure drop (psi)
Δp_h	head loss pressure drop (psi)

Δp_{ke}	inertial loss pressure drop (psi)
Δp_{pump}	external pump work (psi)
$\mathcal{P}_1$	pooled cumulative primary oil production (MSTB) primary near-state variable primary production milestone
$\Delta\mathcal{P}_1$	cumulative primary oil interval (MSTB)
$\mathcal{P}_2$	pooled cumulative secondary oil production (MSTB) secondary near-state variable secondary production milestone
$\Delta\mathcal{P}_2$	cumulative secondary oil interval (MSTB)
PI	well productivity index
q_g	gas mass concentration source/sink (lbs/ ft^3/day)
q_o	oil mass concentration source/sink (lbs/ ft^3/day)
q_w	water mass concentration source/sink (lbs/ ft^3/day)
$\mathcal{Q}$	pooled production rate
Q_g	standard gas volumetric flow rate (Mscf/day)
Q_o	standard oil volumetric flow rate (STB/day)
$\mathcal{Q}_o$	time-averaged pooled oil production rate
$\overline{Q}_o$	daily oil production rate (STB/day)
Q_o^{max}	well maximum oil production rate capacity (STB/day)
Q_w	standard water volumetric flow rate (STB/day)
Q_w^{max}	well maximum water injection rate capacity (STB/day)
r	real risk-free interest rate
r_w	wellbore radius (ft)
R	lumped royalty rate
$\mathscr{R}$	reservoir state (p, S_w, S_g)
$\mathcal{R}_1$	primary action region ($s, t, \mathcal{P}_1$)
$\mathcal{R}_{1A}$	primary early abandonment mode action region ($s, t, \mathcal{P}_1$)
$\mathcal{R}_{1C}$	primary control operating mode action region ($s, t, \mathcal{P}_1$)
$\mathcal{R}_{1S}$	primary suspended operating mode action region ($s, t, \mathcal{P}_1$)
$\mathcal{R}_2$	secondary action region ($s, t, \mathcal{P}_2 ; \mathcal{P}_1$)
$\mathcal{R}_{2A}$	secondary early abandonment mode action region ($s, t, \mathcal{P}_2 ; \mathcal{P}_1$)
$\mathcal{R}_{2C}$	secondary control operating mode action region ($s, t, \mathcal{P}_2 ; \mathcal{P}_1$)
$\mathcal{R}_{2S}$	secondary suspended operating mode action region ($s, t, \mathcal{P}_2 ; \mathcal{P}_1$)
s	stochastic spot oil price ($/bbl)
s_{12}^*	critical waterflood investment price ($/bbl)
s_{1CS}^*	critical primary operating price boundary between active control and suspended operations ($/bbl)

s_{1CA}^*	critical primary operating price boundary for irreversible early abandonment from active control ($/bbl)
s_{1SA}^*	critical primary operating price boundary for irreversible early abandonment from suspended operations ($/bbl)
s_{2CS}^*	critical secondary operating price boundary between active control and suspended operations ($/bbl)
s_{2CA}^*	critical secondary operating price boundary for irreversible early abandonment from active control ($/bbl)
s_{2SA}^*	critical secondary operating price boundary for irreversible early abandonment from suspended operations ($/bbl)
scf	standard cubic foot (1 atm, 60° F)
S	skin factor
S^*	phase volumetric bulk concentration
S_g	gas saturation
S_g^*	normalized gas saturation
S_{gc}	critical mobile gas saturation
S_l	liquid saturation
S_o	oil saturation
S_o^*	normalized oil saturation
S_{org}	residual oil saturation in gas-oil
S_{orw}	residual oil saturation in water-oil
S_w	water saturation
S_w^*	normalized water saturation
S_{wir}	irreducible connate water saturation
STB	stock tank barrel (1 atm, 60° F)
t	time (days)
t_o	cumulative oil production time (days)
Δt^n	time step (days)
$\Delta t_{produce}$	monthly cycle production interval (days)
T	overall strategic plan duration (years) termination time (years) delivery time
T	temperature (° F)
T_{pc}	pseudo-critical temperature (° F)
T_x	block boundary transmissibility (x-direction)
T_y	block boundary transmissibility (y-direction)
T_z	block boundary transmissibility (z-direction)
u	continuously compounded rate of return on spot oil price
$\mathbf{u}$	propagation velocity
v_1	primary variable unit costs ($/STB)
v_2	secondary variable unit costs ($/STB)
$\mathbf{v}_g$	gas Darcy velocity reservoir volumetric flux (ft/day)
$\mathbf{v}_o$	oil Darcy velocity reservoir volumetric flux (ft/day)

$\mathbf{v}_w$	water Darcy velocity reservoir volumetric flux (ft/day)
V_g	reservoir gas volume (reservoir ft^3)
V_o	reservoir oil volume (reservoir bbl)
V_{scg}	gas volume (scf) at standard conditions (1 atm, 60° F)
V_{sco}	oil volume (STB) at standard conditions (1 atm, 60° F)
V_{scw}	water volume (STB) at standard conditions (1 atm, 60° F)
V_w	reservoir water volume (reservoir bbl)
ΔV_b	elemental bulk volume (ft^3)
$\mathcal{V}$	remaining production value ($)
$\mathcal{V}_1$	remaining primary value ($)
$\mathcal{V}_{1A}$	remaining primary value for early abandonment ($)
$\mathcal{V}_{1C}$	remaining primary value under control policy ($)
$\mathcal{V}_{1S}$	remaining primary value under pooled suspension ($)
$\mathcal{V}_2$	remaining secondary value ($)
$\mathcal{V}_{2A}$	remaining secondary value for early abandonment ($)
$\mathcal{V}_{2C}$	remaining secondary value under control policy ($)
$\mathcal{V}_{2S}$	remaining secondary value under pooled suspension ($)
$\Delta\mathcal{V}_{12}$	payoff from waterflood investment option ($)
W_1	dollars invested in holding oil in inventory ($)
W_2	dollars shorted in oil futures contracts ($)
W_3	dollars borrowed at the risk free rate ($)
WI	well injectivity index
WOR	water-oil ratio
Δx	grid block length (ft)
$\mathbf{x}$	coordinate vector (x, y, z)
$\Delta\mathbf{x}$	volume element (ft^3)
$\Delta\mathbf{x}_{ijk}$	grid block volume element (ft^3)
Δy	grid block width (ft)
z	gas deviation factor
z	depth (ft)
$z=0$	sea level
z_0	formation top depth (ft subsea)
Δz	thickness (ft) grid block thickness (ft) mechanical perforation zone thickness (ft)

Greek Symbols

β	instantaneous expected rate of return on the futures contract
β_g	three-phase permeability gas function
β_w	three-phase permeability water function

γ	standard deviation in the rate of return on the futures contract
γ_g	gas gravity (Air=1)
γ_o	oil gravity (Fresh Water=1)
γ_w	saline water gravity (Fresh Water=1)
Δ_s	oil price state difference operator
Δ_t	time difference operator
Δ_x	x-direction difference operator
Δ_y	y-direction difference operator
Δ_z	z-direction difference operator
Δ_1	primary depletion state difference operator
Δ_2	secondary depletion state difference operator
ϕ	rock porosity
Φ_g	gas potential (psi)
Φ_o	oil potential (psi)
Φ_w	water potential (psi)
λ_g	gas mobility
λ_o	oil mobility
λ_w	water mobility
μ	mean rate of return on spot oil price market
μ_g	gas viscosity (cp)
μ_o	oil viscosity (cp)
μ_w	water viscosity (cp)
ρ_g	gas density (lbs/ft^3)
ρ_o	oil density (lbs/ft^3)
ρ_{scg}	gas density (lbs/ft^3) at standard conditions (1 atm, 60° F)
ρ_{sco}	oil density (lbs/ft^3) at standard conditions (1 atm, 60° F)
ρ_{scw}	saline water density (lbs/ft^3) at standard conditions (1 atm, 60° F)
ρ_w	saline water density (lbs/ft^3)
θ_{1A}	terminal primary early abandonment operating mode
θ_{1C}	active primary operating mode under control policy
θ_{1S}	passive primary operating mode pooled suspension
Θ_1	primary operations
θ_{2A}	terminal secondary early abandonment operating mode
θ_{2C}	active secondary operating mode under control policy
θ_{2S}	passive secondary operating mode pooled suspension
Θ_2	secondary operations

σ	non-stochastic annual oil price volatility
τ	time
	time to maturity ($\tau = T - t$).
τ_o	time to fill monthly oil quota (days)
τ_g	time to fill monthly gas quota (days)
$d\zeta$	normal random variable with variance dt
$\Delta\xi$	characteristic length (ft)

Subscripts and Superscripts

A	early abandonment operating mode
C	active control operating mode
g	gas phase
i	discrete (x) coordinate index
	discrete oil price (s) state index
	operation stage index
j	discrete (y) coordinate index
k	discrete (z) coordinate index
m	operating mode index
m_1	discrete ($\mathcal{P}_1$) primary depletion state index
m_2	discrete ($\mathcal{P}_2$) secondary depletion state index
n	discrete (t) time index
o	oil phase
s	oil price
S	suspended pool operating mode
sc	standard conditions (1 atm, 60° F)
w	water phase
x	x-direction
y	y-direction
z	z-direction
1	primary
2	secondary
*	boundary indicator

Chapter 1: Introduction

1.1 Production Stages

An oilfield may have more than one stage of economically viable oil production over its producing life. The first, or primary, production stage uses the natural expansion energy within the reservoir to displace fluids towards producing wells. Primary production declines as the intrinsic supply of potential energy is converted into displacement work. Increasing ultimate oil recovery by the reservoir-scale introduction of extrinsic energy may become a viable option at some point over primary decline. The timing of investment and the implementation that follows can be critical for a depletion strategy whose objective is to maximize the overall project economics. When additional energy can no longer increase recovery in an economic manner, the oilfield will be abandoned.

In primary production, the sources of energy may come from fluid expansion, solution gas drive, water drive, gas cap drive, compaction drive or a combination of these natural depletion mechanisms. The reservoir may be stimulated at or near producing wells by mechanical, chemical, thermal or explosive means. Stimulation technologies, like acidizing and fracturing, attempt to increase well productivity by reducing bottleneck resistances to fluid flow. Artificial lift technologies may also supplement naturally flowing wells with the additional energy needed to pump fluids to the surface.

A depletion strategy may begin to develop as information about reservoir potential materializes in the early phase of primary production. Preferred recovery schemes, based on reservoir characteristics, fluid properties and reservoir state, may then be considered for the next stage of oil production. Various schemes have been developed to enhance oil recovery for different reservoir scenarios. These enhanced oil recovery (EOR) schemes are classified as secondary or tertiary technologies. Secondary recovery schemes, like pattern waterflooding, immiscible gas flooding and pressure maintenance by water or immiscible gas injection, supplement the natural expansion energy of the reservoir. Tertiary recovery schemes, like hydrocarbon miscible flooding, miscible CO_2 flooding, steamflooding and in situ combustion, introduce chemical or thermal energy into the reservoir system to reduce the viscous and interfacial forces that impede porous media flow. Each recovery scheme may have many variations which implement different flood patterns and operating practices. Each application will be unique and require customized engineering solutions to address the specific design problems.

1.2 Secondary Recovery Option

While most depletion strategies with enhanced recovery options have common economic objectives, their implementation will differ from case to case. This work has chosen to supplement the theoretical development for constructing optional-stage depletion strategies with a realistic application to a particular oilfield. The reservoir example used throughout this work is the Chedderville Viking "A" Pool located 160 km southwest of Edmonton, Alberta, Canada. This is a light oil pool in early primary production. The depletion strategy constructed for this pool considers an optional secondary recovery stage by pattern waterflood. Although the reservoir aspects of this study will be field specific, the production forecasting methodology and the economic decision model can be extended to most operations that consider an optional recovery stage.

Ultimate recovery from this particular reservoir will depend on the depletion strategy that manages both natural depletion under primary production and pattern waterflooding under secondary recovery. Factors that can be controlled by human intervention in primary production include the number, placement, timing and control of production wells. Well capabilities can be enhanced by stimulation to increase wellbore permeability and installation of artificial lift equipment to lower flowing bottomhole pressures. In secondary recovery, additional degrees of freedom will include the number, placement, timing and control of water injection wells. Production will depend on the multi-phase flow of oil, water and gas through the overall production system of porous reservoir media, subsurface equipment, vertical and directional tubings and casings, horizontal and inclined surface flow lines, and flow through any restrictions and chokes. Peak liquid production will be limited by reservoir productivity and the design capacity of the facilities for gathering, separating and treating produced fluids. Peak water injection will be limited by reservoir injectivity and the design capacity of the injection system and water source. Regulatory constraints may limit monthly oil and gas production and restrict minimum well spacing. Well workovers and installation of new equipment may interrupt production continuity.

The engineering design objective attempts to minimize pressure drops in each portion of the production system such that optimal flow conditions are achieved at maximum efficiency. The integrated system design between reservoir and surface facilities is highly complex and requires accurate relationships between flow rates and pressures. Economic criteria determines the scaling decisions that fix the number of wells and size the surface facilities accordingly. Economic criteria also determine the timing decisions for drilling new wells, adding new equipment, expanding existing facilities, implementing waterflood projects and abandoning field operations. Finally, economic criteria determine the control decisions for daily and monthly production from individual wells, and collectively from the entire pool.

1.3 Objectives

The objective of the present work is to develop a methodology using reservoir simulation for constructing optional-stage depletion strategies that incorporate a probabilistic economic model for the timing valuation of recovery options. The tasks set forth are:

1) To approximate depletion state variables based on cumulative oil production and to define a feasible depletion space for primary and secondary operations.

2) To formulate a branched differential decision process model and use dynamic programming techniques to find investment and operating decision rules that maximize the modelled economic value of remaining operating alternatives over a strategic window. The time-dependent project value is to depend on the state of oil price, the state of depletion and the depletion strategy. An intertemporal equilibrium asset valuation model, based on oil futures price dynamics, is to be used to value production cash flows from alternative recovery paths in terms of macro-economic factors and field-specific costs. The decision model is to be based on probabilistic economic scenarios that examine nested primary and secondary operating modes for active control policy, pooled suspension and early abandonment. The dynamic programming algorithm is to track the feasible depletion state boundary constraint for decision times based on cumulative production milestones.

3) To develop a reservoir simulation tool with branched forecasting capabilities for an optional secondary recovery stage at discrete depletion states along the primary life cycle. A three-dimensional, three-phase black oil reservoir simulation tool is to be adapted to forecast waterflood branches in a production tree. A user-friendly simulation tool with dynamic memory allocation, keyword parsing and tree data structures is to be developed in a Microsoft Excel 5.0 workbook environment with program modules in Visual Basic. Tabular data, three-dimensional array data and structured well control schedules are to be organized in multiple worksheets of a common simulation workbook.

4) To develop a well management system for monthly oil and gas regulatory quotas and implement the system into the reservoir simulation tool. The model production rate regulator and accounting system is to be based on Alberta oil and gas monthly allowables where constrained production cycles for monthly gas production has precedence over monthly oil production.

5) To propose a primary control policy that adheres to regulatory constraints and a secondary control policy to meet waterflood design specifications. The control policies are to be based on heuristics that govern the individual rate specification for single well entities and collective rate specifications for blocks of wells.

6) To demonstrate the realistic application of the optional-stage depletion strategy methodology for the Chedderville Viking "A" Pool. In order to demonstrate the realistic application this work has chosen to :

a) characterize the reservoir for Chedderville Viking "A" using geostatistics
b) match historical production and pressure data
c) design a feasible waterflood project
d) propose a primary control policy that adheres to regulatory constraints
e) propose a secondary control policy to meet design objectives
f) forecast waterflood production branches along the primary life cycle
g) generate a model depletion strategy for Chedderville Viking "A"
h) analyze the investment timing option and determine the economic limit

1.4 Guiding Philosophy

The main factor effecting primary oil recovery is the natural depletion mechanism. The decision to continue with primary operations will depend on the expected value of remaining primary production forecasts. Production forecasts will depend on primary controls and expansion decisions. Waterflooding is a proven secondary technology to improve oil recovery. Solution gas drive reservoirs like Chedderville Viking "A" are good candidates for waterflooding. The decision to waterflood will depend on the expected payoff from predicted waterflood oil production. Waterflood prediction will depend on waterflood design and secondary control decisions.

An optimality criterion for waterflood design is somewhat evasive and the concept misleading. A truly optimal design would determine the number, placement, timing and control of wells to maximize expected project value in accordance with regulatory constraints and economic criteria. The design choice may not necessarily be unique, with different configurations and policies leading to the same project value. Different configurations may become more attractive as the probability structure of macro-economic scenarios unfold with time. The problem here is not to find an optimal design, but to find optimal decision rules for a particular design.

A waterflood strategy with a fixed pattern design may be tailored for a particular primary depletion state. The same waterflood may or may not perform as well for other primary depletion states. The design process concentrates on refining performance for a unique primary depletion state at a particular point in time. The decision process defines rules for choosing the fixed design at different times over primary decline.

Secondary waterflood depletion paths branch from originating primary depletion states. The waterflood investment decision will compare the net value of initiating a secondary recovery stage with the remaining value of primary production. Waterflood stage recoveries may change with declining primary production. Economic evaluation should consider the timing impact of how these changes will affect the overall project value.

Before any informed decisions can be made to manage the reservoir economically, or plan for future operations, management personnel should know what it is they are trying to manage. They should acquire sufficient information about the reservoir characteristics through core samples, logs, well tests, fluid samples and accumulated production history to forecast the production capability of the entire pool. Reliability of the production forecast will depend on the analysis techniques used, validity of the data measured and availability of information.

A depletion strategy will emerge as reservoir characteristics and production capabilities are better understood. Design and operating decisions will be made to economically manage the reservoir and plan for future operations. Some decisions will react to changing economic conditions and unfolding physical events. Control strategies will establish guiding policies to improve existing operations and design future expansions.

Management personnel should have some measure of how effective their decisions will be and how they will attain the objectives set forth. They need to know what they can do and how to do it. Management personnel should be familiar with all aspects of their operation and have a system to facilitate decision-making. They should have some means to forecast performance of the overall production system and have the ability to test the outcomes from the decisions they can make.

Before a depletion strategy can be analyzed on the model system, the reservoir model should first be validated with historical data. The reservoir simulation tool has limitations that rest on the accuracy of the reservoir description, the bias of the underlying model and the discretization errors in numerical solution. The integrity of simulation results depends on the quality of production and pressure data, and the ability to calibrate the model accurately by history matching. Model rejection or acceptance will depend on the degree of fit. The degree of fit will depend on interacting performance criteria and will tend to be subjective in some cases.

1.5 Sources of Data

The data for Chedderville Viking "A" was provided by Canadian Hunter Exploration Ltd. of Calgary, Alberta, for the undergraduate Design Course, PET.E. 496, instructed by Dr. Q.T. Doan at the University of Alberta. The data package included:

- geological and geographic data
- well completions, perforation zones and stimulation treatments data
- core data and well log data
- PVT data
- capillary pressure data (Canadian Hunter Waterflood Design Study)[1]
- relative permeability data (Canadian Hunter Waterflood Design Study)
- monthly production data
- bottomhole pressure data (Energy Resources Conservation Board)
- maximum monthly rate limitations and gas-oil ratios
- well capital cost data

Supplementary data was obtained from GEOBASE, CD PUBCO Inc., Calgary, Alberta, to corroborate production histories and well data.

Typical operating costs for Alberta oilfields were obtained through direct consultation with the Alberta Department of Energy[2]. These included:

- fixed operating costs per well
- variable operating costs per barrel of oil produced
- water injection conversion costs
- well abandonment costs correlated with depth

Macro-economic data for representative average monthly oil prices were obtained from The Monthly Commodity Price Bulletin. Nominal risk-free interest and inflation rates were based on data from the Canadian Economic Observer (Nov 1994), Statistics Canada Catalogue No. 11-010 Monthly.

- Dubai, U.K. Brent and Alaska Average, SPOT, F.O.B. (1991-1994)
- Government of Canada 3-month Treasury Bills (1994)
- Consumer Price Index (1994)

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[1] Canadian Hunter Chedderville Waterflood Design Study, Hycal Energy Research Laboratories Ltd., Calgary, Oct 25, 1993.

[2] Consultation with John E. Faltinson, Alberta Department of Energy.

Chapter 2: Reservoir Characterization

2.1 Reservoir Description Process

Field data is sparse and irregular, with point estimates at a few wells dispersed over a relatively large reservoir domain. Average values can suffice to represent three-dimensional (3-D) macroscopic properties for reservoirs with small variations in sample data. Large variations and discontinuities must be resolved by refining reservoir attributes with a descriptive model. Different recovery schemes for different reservoir conditions will require different simulation models. Reservoir simulators are engineering tools used to forecast production for particular sets of production and reservoir criteria. The simulation model outlined in Appendix A1 describes the observed reservoir flow behaviour in Chedderville Viking "A" and can be used to predict future waterflood response. This model requires data filled on a block-centered grid. The modelling objective set forth is to sufficiently describe the reservoir with the simplest possible grid.

The actual variation in reservoir properties between point estimates is uncertain. The sample represents a single realization from a distribution of possible reservoir conditions. Rock attributes are randomly distributed at the microscopic scale, but may have certain trends at the macroscopic scale. The description process used to characterize the reservoir assumes macroscopic continuity within the reservoir domain bounded by known geological barriers.

The choice in grid size may be constrained by computational power. The areal partition selected in this work used a 10-acre (0.125 mile × 0.125 mile) grid overlay. Many data fill techniques are available to generate regular matrices from irregular data. Commercially available software, such as Spyglass® Transform, provides nearest neighbour, kernel smoothing, linear interpolation, weighted fill and kriging methods. Of these, kriging is preferred. Kriging uses a weighted calculation to minimize the statistical variance of the array according to their distance (Delhomme 1978). All data fill operations in the description process for Chedderville Viking "A" used Spyglass® Transform kriging with a spherical distribution function and the largest possible sample size per kriging pass. The original sample values were preserved and default settings were used for the kriging parameters of range, variance and nugget. The nugget parameter is the minimum variance value for unknown data values. Data manipulation and processing was performed with Microsoft Excel® 5.0 for organizing, tabulating, calculating and plotting numeric information. Customized mapping software was developed using Microsoft Visual Basic® modules in the Microsoft Excel® 5.0 environment.

Even with these tools, obtaining a representative reservoir description is more of an art than a science. The description process for each reservoir property is coupled with the description processes for all other reservoir properties, and is iterative in nature. The initial model may be adjusted and recast many times before an acceptable representation is attained through history matching production and pressure data (Mattax and Dalton, 1990). Manual history matching involves the recursive refinement of input data subject to the degree of fit between simulation output and historical performance measurements. The reservoir data presented in this chapter is the data input for the three-dimensional, three-phase black oil simulator. This chapter shows only the final results obtained over countless trials of iterative history matching, and outlines some of the problem-solving difficulties incurred.

2.2 Reservoir Simulation

Mattax and Dalton (1990) discuss a wide range of reservoir simulation topics and give a good overview of the subject. The reservoir simulation model used in this work describes simultaneous multiphase fluid flow of oil, water and gas in porous media to predict oil production from the reservoir (Farouq Ali 1980). The black oil reservoir model accounts for fluid and rock compressibility, gas-oil and gas-water solubilities, oil-water and gas-oil capillary pressures, three-phase relative permeabilities and variable bubble point pressures. The simulator can handle the non-linearities in fluid properties, heterogeneities in the reservoir, discontinuities in the geology and multi-well control. A well management system model allows for scheduling and regulation of wells under maximum monthly rate limitations and maximum gas-oil ratios. The well management system model is described in Chapter 3.

Reservoir simulators solve the nonlinear partial differential equations describing porous media flow using numerical finite-difference techniques. The material balance formulation using Darcy-continuity equations is outlined in Appendix A1. The formulation is based on the "Black Oil Applied Simulation Tool (BOAST)" developed in FORTRAN by Franchi *et al.* (1982). The model uses the implicit-pressure explicit-saturation (IMPES) sequential solution procedure (Sheldon *et al.* 1960, Stone and Garder 1961). This method solves the derived oil pressure equation implicitly and then determines phase saturations explicitly using calculated pressures. Finite-difference equations are solved using a direct method with symbolic D4-ordering (Oguztoreli 1984, Oguztoreli 1988). The actual simulator implementation used Microsoft Visual Basic modules in a Microsoft Excel 5.0 workbook. This software development environment was chosen for its user interface with built-in spreadsheet, charting and programming facilities. The simulator developed for this work has improved modifications in well management, state initialization, three-phase relative permeability, cubic spline interpolation, performance data accounting, branched production trees and overall user interface. Tracking branched production possibilities on a data tree structure is the foundation for analyzing the timing impact of an optional waterflood stage.

The three-dimensional three-phase black oil reservoir simulator is capable of forecasting primary production and waterflood for most, but not all, reservoir conditions. In this simulation study, we must keep in mind that production forecasts become increasingly less reliable as projected further into the future, and should be interpreted as a quantitative guide, rather than the absolute rule.

2.3 State of Reservoir Information

The current state of primary production operations in the Chedderville Viking "A" pool is defined on the calendar date of October 1, 1994. The initial state, marked by the first production record from the pool, is defined on the calendar date of November 1, 1987. Reservoir data was extracted from the Canadian Hunter (1994) data package and GEOBASE (1993). This information can be grouped as:

- geological and geographic data
- well perforation zone data
- core data and well log data
- PVT data
- capillary pressure data
- relative permeability data
- bottomhole pressure data
- production data

2.4 Geological and Geographic Data

The Viking "A" pool in the Chedderville field is located 160 km southwest of Edmonton in the legal subdivisions of township 37, ranges 7 and 8, west of meridian 5. The hydrocarbon bearing deposit lies in the Viking Sandstone formation between overlying Shaftesbury Sea shales and underlying Joli Fou shales. The reservoir was initially classified as undersaturated with ordinary black oil. This is a light oil pool in early primary production with 19 wells drilled at the time of investigation (Oct 1994). These wells are listed in geographic and historical orders in Tables 2.1(a) and (b), respectively. Figure 2.1 shows the location of these wells with respect to their legal subdivisions. Reservoir boundaries are delineated by sandstone continuity and fluid transmissibility through pressure communication with adjacent media. A fault defines the western boundary which separates Viking "A" and Viking "S" pools. The oil-bearing deposit thins out at the northern edge and virtually vanishes at wells 14-18-37-7W5 and 04-22-37-7W5. The southern boundary isolates Viking "B" and is marked by a sudden reduction in rock permeability to fluid transmission and by a thinning of pay zone.

2.5 Perforation Zone Data

Most of the well data was consistent between Canadian Hunter (1994) and GEOBASE (1993), however, discrepancies were evident in perforation zone depths. Depths are measured from kelly bushing elevations at the surface. Geological revisions in GEOBASE (1993) to the original perforation zone depths had been made to those wells directionally drilled at or near the subtle fault delineating the western pool boundary (Figure 2.1). Earlier estimates of the reservoir structure and associated oil in place had also been revised as new information concerning pressure communication was revealed through the addition of new wells to the pool. The revised perforation data from GEOBASE (1993) was used in this work. These perforation zones are assumed as net pay and their corresponding depths and thicknesses are listed in Tables 2.1(a) and 2.1(b).

Typically, a principal axis transformation aligns the areal coordinate system with core-maximum and core-90° permeability trends in the reservoir. These longitudinal and transverse permeability directions corresponds to the x-axis and y-axis, respectively. The longitudinal x-axis is assumed to coincide with the east-west length of the pool. The reservoir was delineated on a regular 64×24 10-acre areal grid overlay (Figure 2.2). Delineation was based on contour-thresholding a kriged reservoir thickness above 3.75 feet. A boundary mask was superimposed to reflect the discontinuity at the western fault and the segmentation of Viking "B". Kriged reservoir thickness was forced continuously to 0.5 feet at northern and southern edges to align east-west with abandoned dry-hole wells. Viking "C" was also segmented by forcing thickness continuity of 0.5 feet at the north-eastern corner of the grid. The grid boundary was fine-tuned manually with contour and surface plot visualization as shown in Figures 2.3(a) and 2.3(b), respectively. Fine-tuning adjustments were made to maintain region convexity, long boundary runs and smooth boundary transitions. A high ridge with a continuous east-west crest was forced over the mid-length of the reservoir, after feedback from pressure history matching indicated a larger deposit than initially interpolated. The final trimmed reservoir geometry fit on a 54×18 grid with an areal span of 6450 acres and an average thickness of $\Delta z=16.8$ feet. The resulting boundary was used to areally mask all other reservoir properties which were kriged without any forcing boundary constraints. Kelly bushing elevation contour and surface plots are shown in Figures 2.4(a) and (b). Contour and surface plots for the sub-sea depth of the reservoir top are shown in Figures 2.5(a) and (b). The pool has and east-west dip, from 4900 feet at the eastern edge to 5250 feet at the western boundary.

	Chedderville Viking A Well Data Base					Spud Date	Flow Status	Core Sample	Kelly Bushing Elevation (ft)	Perf Top Depth KB (ft)	Perf Bottom Depth KB (ft)	Zone Thickness (ft)	Perf Top Depth Subsea (ft)	Perf Bottom Depth Subsea (ft)
Well	LSD	SEC	TWP	RGE	W									
1	8	7	37	7	5	30-Nov-93	Flowing/Pumping	YES	3567.6	8684.4	8704.1	19.7	5116.8	5136.5
2	14	7	37	7	5	8-Jun-93	Flowing/Pumping	YES	3546.6	8668.0	8697.5	29.5	5121.4	5150.9
3	8	8	37	7	5	18-Oct-87	Viking B		3575.5	8645.0	8658.1	13.1	5069.6	5082.7
4	16	8	37	7	5	18-Jul-92	Flowing/Pumping	YES	3530.5	8546.6	8582.7	36.1	5016.1	5052.2
5	8	9	37	7	5	18-Oct-87	Abandoned		3533.1	8525.3	8526.9	1.6	4992.1	4993.8
6	14	9	37	7	5	8-Feb-86	Flowing/Pumping	NO	3524.3	8507.2	8517.1	9.8	4982.9	4992.8
7	16	9	37	7	5	15-Sep-87	Flowing/Pumping	NO	3556.8	8526.9	8540.0	13.1	4970.1	4983.3
8	6	14	37	7	5	22-Nov-87	Capped Gas	YES	3482.9	8366.1	8389.1	23.0	4883.2	4906.2
9	6	15	37	7	5	28-Nov-88	Flowing/Pumping	YES	3504.6	8425.2	8444.9	19.7	4920.6	4940.3
10	6	16	37	7	5	28-Jul-90	Flowing/Pumping	NO	3507.2	8431.8	8448.2	16.4	4924.5	4940.9
11	8	17	37	7	5	19-Feb-93	Flowing/Pumping	YES	3485.9	8507.2	8520.3	13.1	5021.3	5034.4
12	8	18	37	7	5	21-Feb-92	Flowing/Pumping	NO	3536.4	8615.5	8628.6	13.1	5079.1	5092.2
13	14	18	37	7	5	28-Nov-90	Abandoned		3520.3	8663.1	8664.7	1.6	5142.7	5144.4
14	4	22	37	7	5	14-Mar-64	Abandoned		3429.1	8376.0	8379.3	3.3	4946.9	4950.1
15	14	12	37	8	5	30-Jul-93	Flowing/Pumping	NO	3592.8	8838.6	8871.4	32.8	5245.7	5278.5
16	16	12	37	8	5	26-Aug-93	Flowing/Pumping	NO	3581.4	8736.9	8763.1	26.2	5155.5	5181.8
17	6	13	37	8	5	10-Mar-90	Flowing/Pumping	YES	3572.8	8779.5	8792.7	13.1	5206.7	5219.8
18	8	13	37	8	5	20-Dec-89	Flowing/Pumping	NO	3576.8	8733.6	8746.7	13.1	5156.8	5169.9
19	8	14	37	8	5	27-Sep-90	Flowing/Pumping	YES	3608.9	8851.7	8864.8	13.1	5242.8	5255.9

Table 2.1(a): Chedderville Viking "A" Well List Geographic Order (Oct-94)

	Chedderville Viking A Well Data Base					Spud Date	Flow Status	Core Sample	Kelly Bushing Elevation (ft)	Perf Top Depth KB (ft)	Perf Bottom Depth KB (ft)	Zone Thickness (ft)	Perf Top Depth Subsea (ft)	Perf Bottom Depth Subsea (ft)
Well	LSD	SEC	TWP	RGE	W									
14	4	22	37	7	5	14-Mar-64	Abandoned		3429.1	8376.0	8379.3	3.3	4946.9	4950.1
6	14	9	37	7	5	8-Feb-86	Flowing/Pumping	NO	3524.3	8507.2	8517.1	9.8	4982.9	4992.8
7	16	9	37	7	5	15-Sep-87	Flowing/Pumping	NO	3556.8	8526.9	8540.0	13.1	4970.1	4983.3
3	8	8	37	7	5	18-Oct-87	Viking B		3575.5	8645.0	8658.1	13.1	5069.6	5082.7
5	8	9	37	7	5	18-Oct-87	Abandoned		3533.1	8525.3	8526.9	1.6	4992.1	4993.8
8	6	14	37	7	5	22-Nov-87	Capped Gas	YES	3482.9	8366.1	8389.1	23.0	4883.2	4906.2
9	6	15	37	7	5	28-Nov-88	Flowing/Pumping	YES	3504.6	8425.2	8444.9	19.7	4920.6	4940.3
18	8	13	37	8	5	20-Dec-89	Flowing/Pumping	NO	3576.8	8733.6	8746.7	13.1	5156.8	5169.9
17	6	13	37	8	5	10-Mar-90	Flowing/Pumping	YES	3572.8	8779.5	8792.7	13.1	5206.7	5219.8
10	6	16	37	7	5	28-Jul-90	Flowing/Pumping	NO	3507.2	8431.8	8448.2	16.4	4924.5	4940.9
19	8	14	37	8	5	27-Sep-90	Flowing/Pumping	YES	3608.9	8851.7	8864.8	13.1	5242.8	5255.9
13	14	18	37	7	5	28-Nov-90	Abandoned		3520.3	8663.1	8664.7	1.6	5142.7	5144.4
12	8	18	37	7	5	21-Feb-92	Flowing/Pumping	NO	3536.4	8615.5	8628.6	13.1	5079.1	5092.2
4	16	8	37	7	5	18-Jul-92	Flowing/Pumping	YES	3530.5	8546.6	8582.7	36.1	5016.1	5052.2
11	8	17	37	7	5	19-Feb-93	Flowing/Pumping	YES	3485.9	8507.2	8520.3	13.1	5021.3	5034.4
2	14	7	37	7	5	8-Jun-93	Flowing/Pumping	YES	3546.6	8668.0	8697.5	29.5	5121.4	5150.9
15	14	12	37	8	5	30-Jul-93	Flowing/Pumping	NO	3592.8	8838.6	8871.4	32.8	5245.7	5278.5
16	16	12	37	8	5	26-Aug-93	Flowing/Pumping	NO	3581.4	8736.9	8763.1	26.2	5155.5	5181.8
1	8	7	37	7	5	30-Nov-93	Flowing/Pumping	YES	3567.6	8684.4	8704.1	19.7	5116.8	5136.5

Table 2.1(b): Chedderville Viking "A" Well List Historical Order (Oct-94)

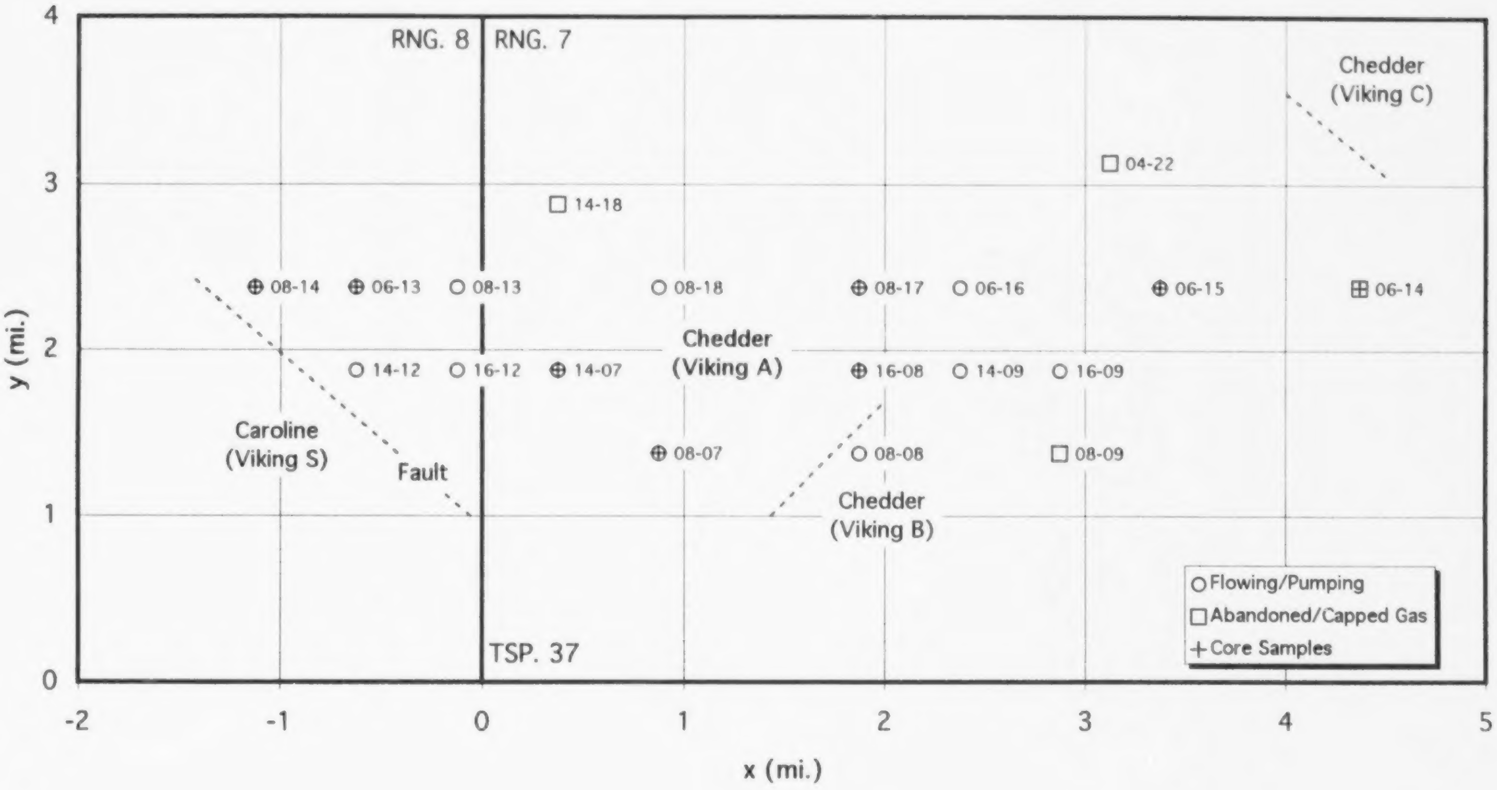

RNG. 8
RNG. 7
TSP. 37
Chedder
(Viking C)
Chedder
(Viking A)
Chedder
(Viking B)
Caroline
(Viking S)
Fault
04-22
14-18
08-14
06-13
08-13
08-18
08-17
06-16
06-15
06-14
14-12
16-12
14-07
16-08
14-09
16-09
08-07
08-08
08-09
○ Flowing/Pumping
□ Abandoned/Capped Gas
+ Core Samples
y (mi.)
x (mi.)
0
1
2
3
4
-2
-1
0
1
2
3
4
5

Figure 2.1: Chedderville Viking "A" Well Location Map

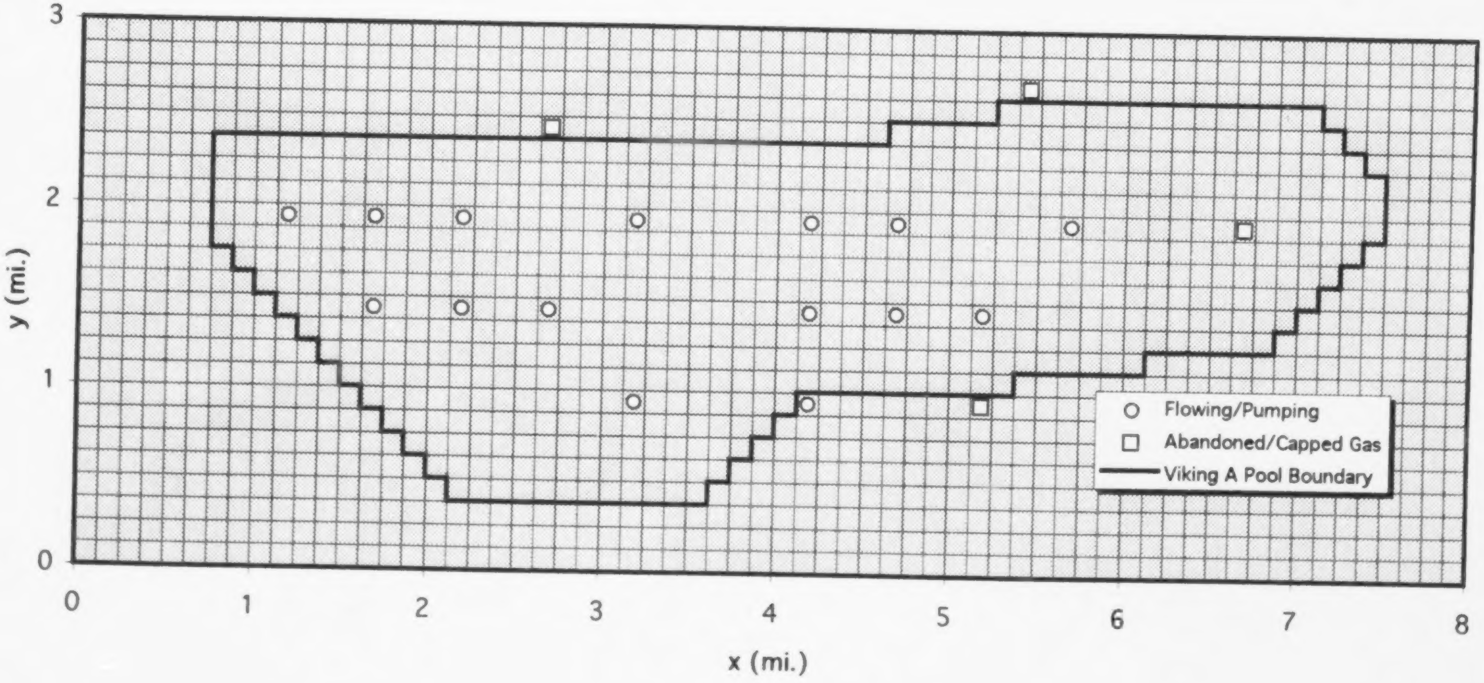


Figure 2.2: Chedderville Viking "A" Grid (10 Acre) Overlay

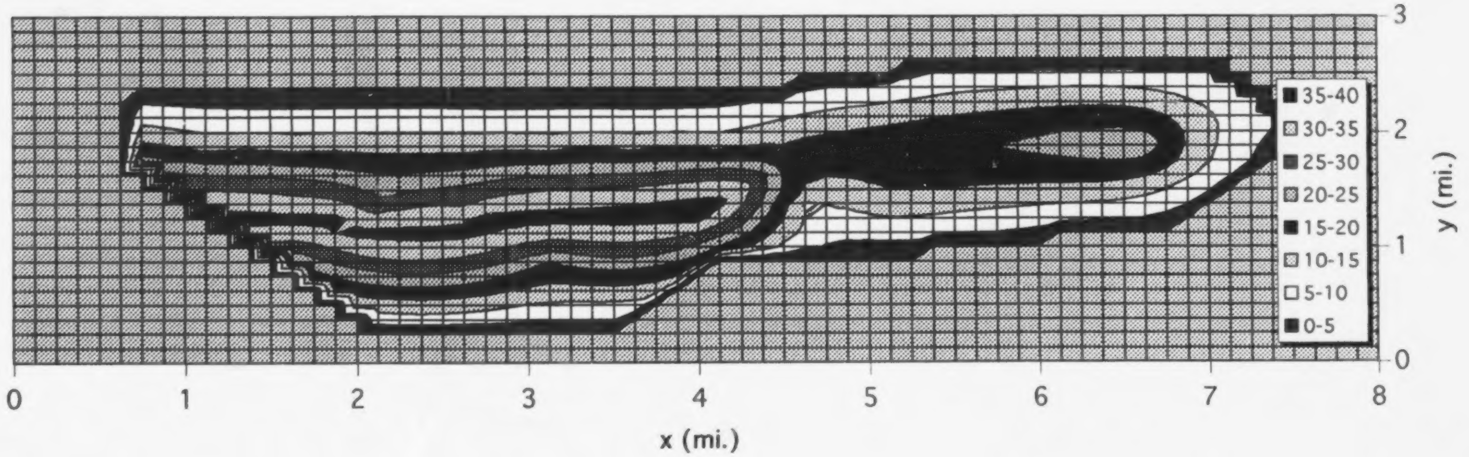


Figure 2.3(a): Reservoir Thickness Δz (ft)

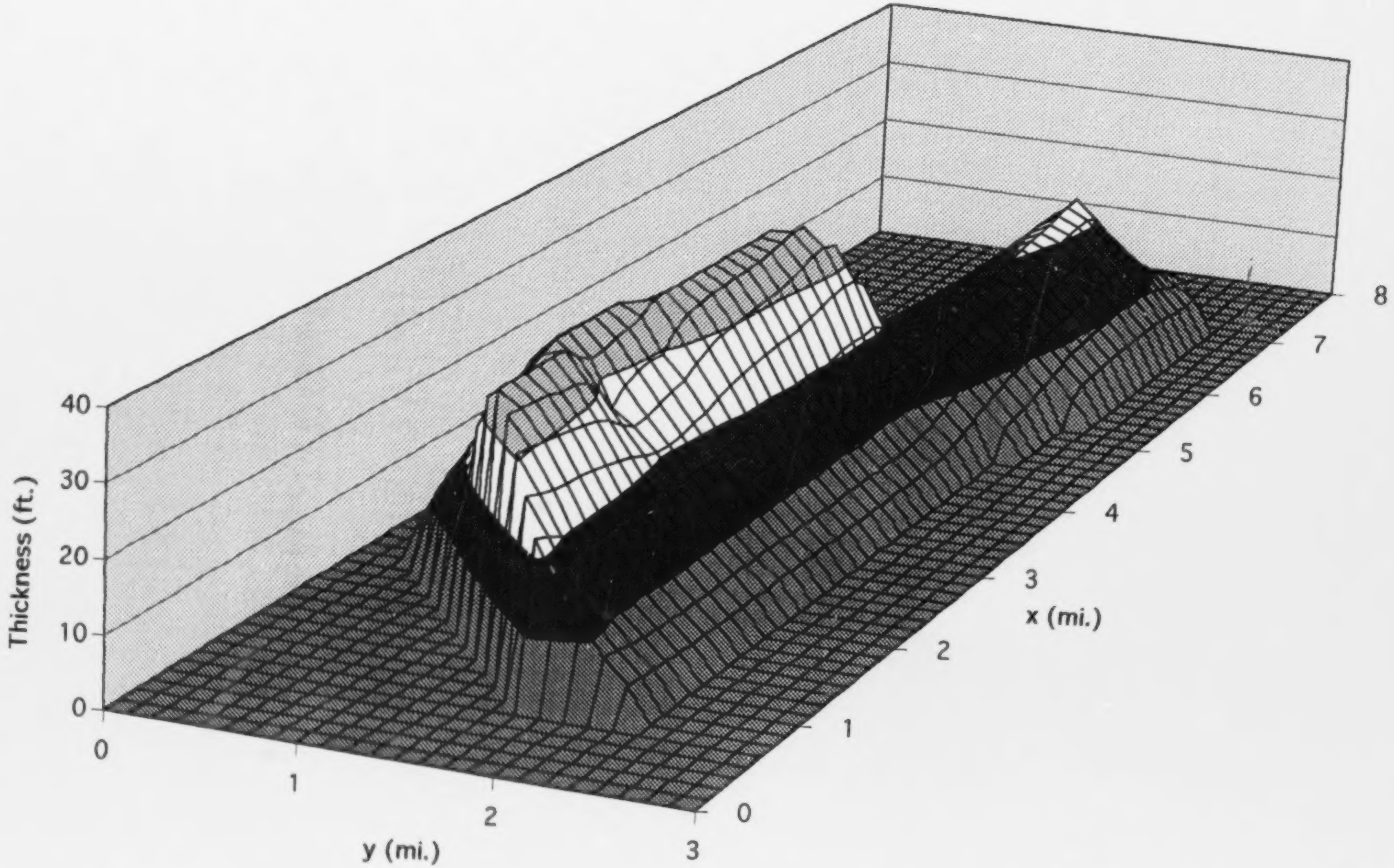


Figure 2.3(b): Reservoir Thickness Δz

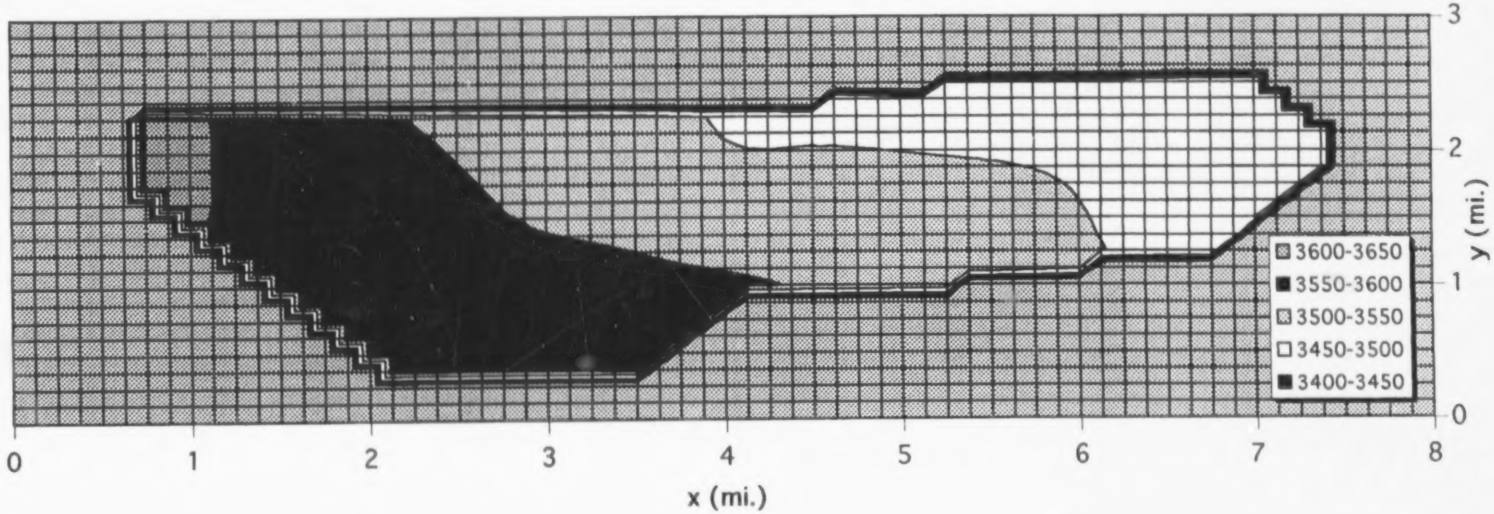


Figure 2.4(a): Kelly Bushing Elevation Contours (ft.)

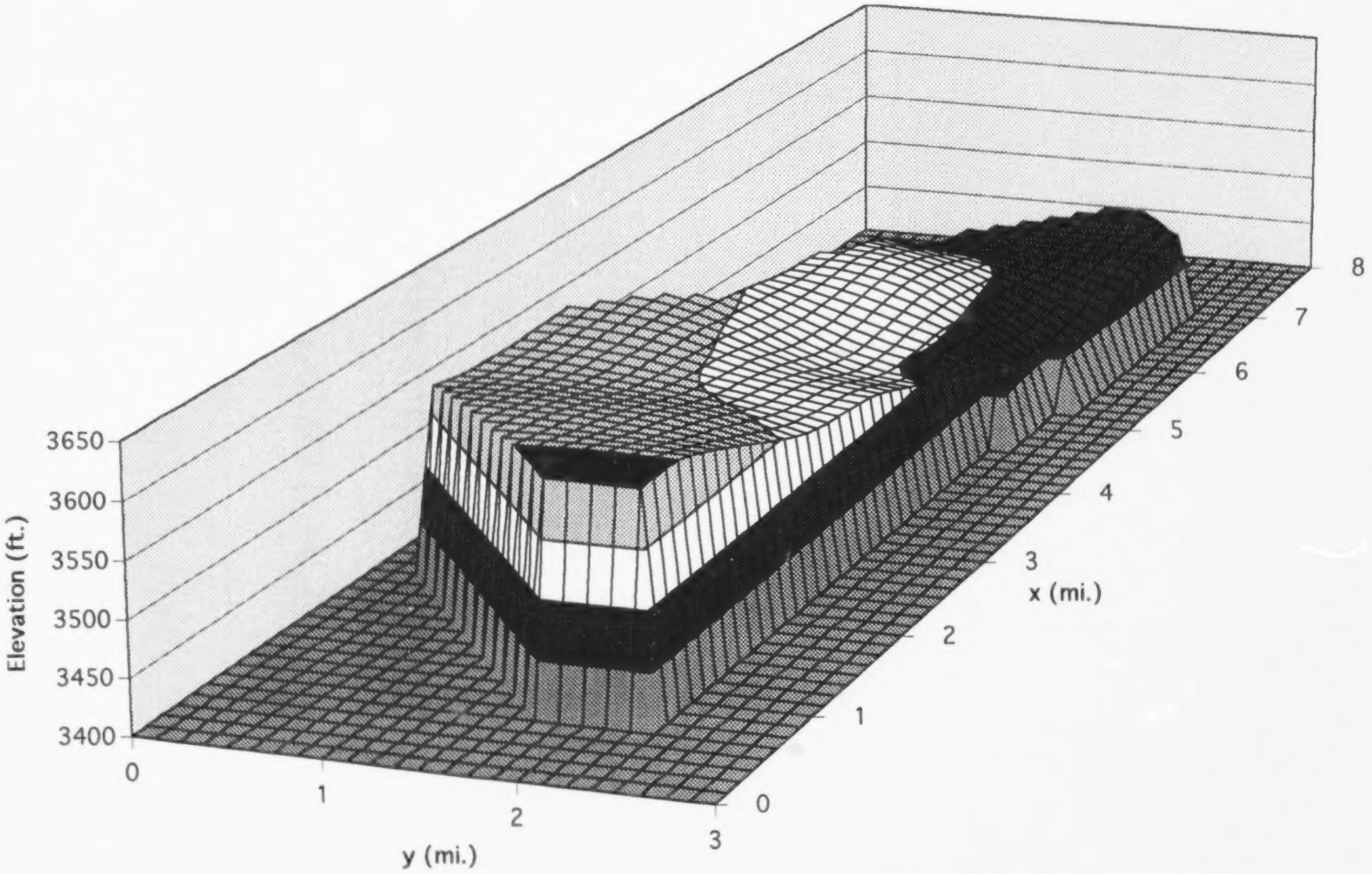
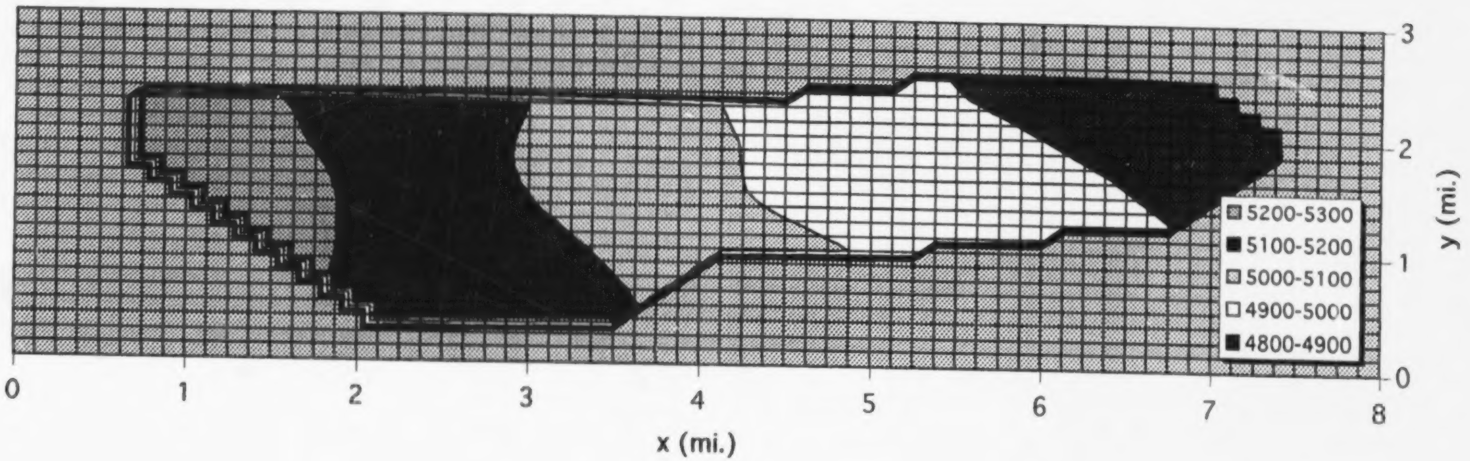


Figure 2.4(b): Kelly Bushing Elevation Surface



▨ 5200-5300
■ 5100-5200
▨ 5000-5100
□ 4900-5000
■ 4800-4900
0
1
2
3
4
5
6
7
8
x (mi.)
0
1
2
3
y (mi.)

Figure 2.5(a): Reservoir Top Subsea Depth (ft)

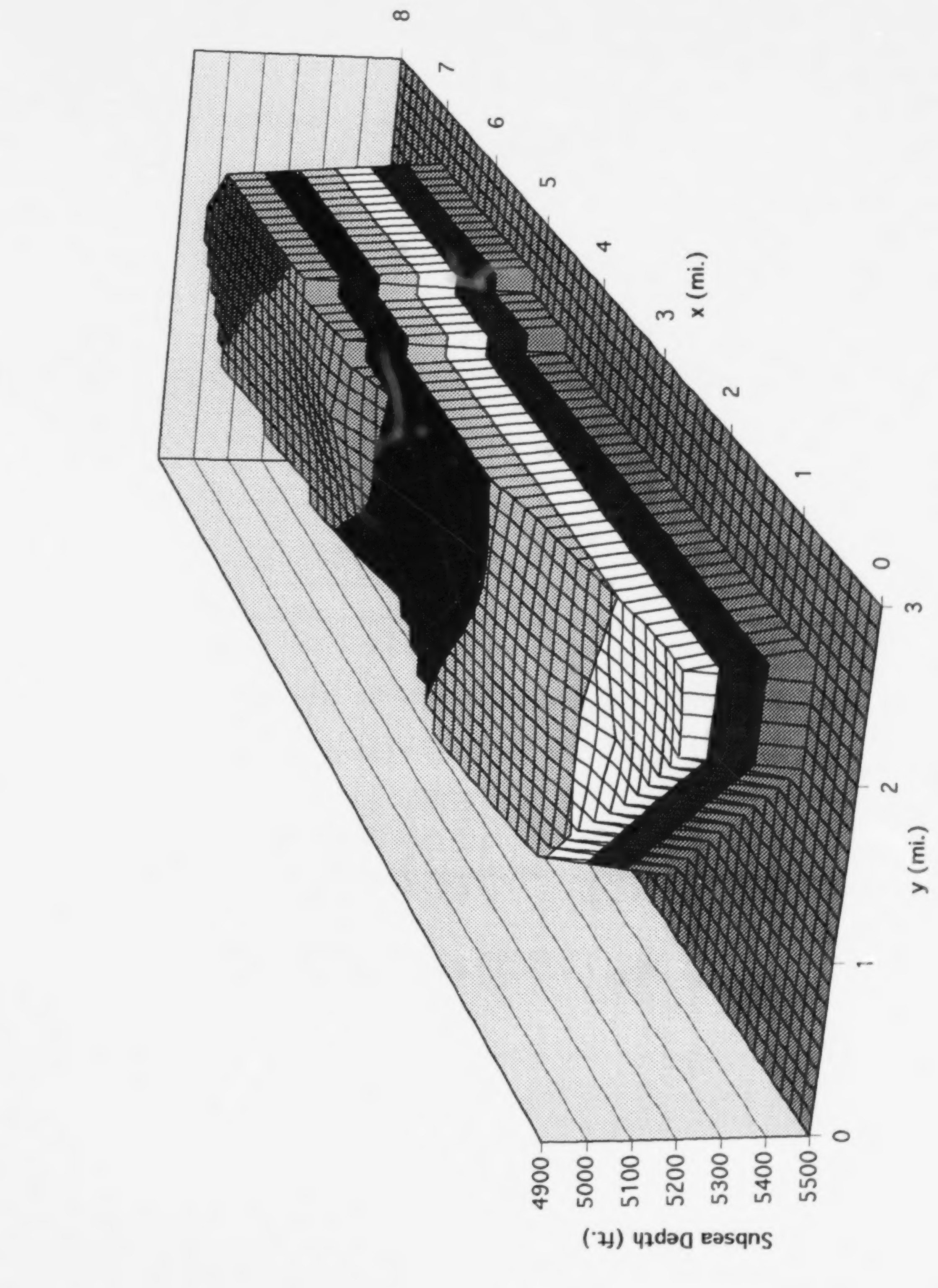


Figure 2.5(b): Reservoir Top Depth

2.6 Core and Well Log Data

Table 2.1(b) indicates wells with core samples taken from relevant perforation zones. The state of core data is incomplete with partial, or no, analysis performed on some perforation zones. The available core data for porosity and absolute permeability from eight wells are listed in Table 2.2. Thickness-weighted porosity averages and geometric log-mean permeabilities are calculated for each core sample.

Porosity is defined as the locally-averaged void volume-fraction of the rock matrix. Porosity histograms for individual core samples and for the aggregate are plotted in Figure 2.6(a). The aggregate sample indicates the presence of two populations with lognormal distributions. These populations are segmented in Figure 2.6(b) into major and minor components, with log mean porosities of ϕ=6.4% and ϕ=2.3%, respectively. The rock is a conglomerate. Porosity trends with respect to zone depth, top-to-bottom, east-west and north-south are shown in Figures 2.7(a)-(d). No marked trends with respect to depth and areal directions are distinguishable. Only the top-to-bottom distribution shows an increasing porosity trend.

Maximum core permeability histograms for individual core samples and for the aggregate are plotted in Figure 2.8(a). The aggregate sample indicates the presence of two populations with lognormal distributions. These populations are segmented in Figure 2.8(b) into major and minor components, with log mean maximum permeabilities of K_x=3.3 md and K_x=1220 md, respectively. The major component is attributable to the bulk of matrix rock and the minor component is interpreted as a high-permeability channel. Maximum permeability trends with respect to zone depth, top-to-bottom, east-west, north-south and core porosity are shown in Figures 2.9(a)-(e). The high-permeability channel seems to persist throughout the length of the reservoir and is concentrated in the northern sections. It seems to be limited to the top portion of the perforation zone and does not wane or wax with depth. Closer inspection of the original core data in Table 2.2 marked a 1.0-2.5 feet high-permeability zone within contiguous wells. Figure 2.9(e) shows the correlation between maximum core permeability and core porosity (correlation coefficient =0.243).

$$\log_{10} K_x = .223 + 8.09\phi \tag{2.1}$$

Transverse 90° core permeability histograms for individual core samples and for the aggregate are plotted in Figure 2.10(a). The aggregate sample also indicates the presence of two populations with log-normal distributions. These populations are segmented in Figure 2.10(b) into major and minor components, with log mean 90° permeabilities of K_y=3.0 md and K_y=855 md, respectively.

Similarly, the major component is attributable to the bulk rock matrix and the minor component is interpreted as a high-permeability channel. Transverse 90° permeability trends with respect to zone depth, top-to-bottom, east-west, north-south and core porosity are shown in Figures 2.11(a)-(e). Transverse 90° permeability is highly correlated with maximum permeability (correlation coefficient=0.943).

$$\log_{10}K_y = -.035 + .848 \log_{10}K_x \tag{2.2}$$

Figure 2.11(e) shows the correlation between 90° core permeability and core porosity (correlation coefficient =0.374).

$$\log_{10}K_y = .0074 + 9.82\phi \tag{2.3}$$

Vertical core permeability histograms for individual core samples and for the aggregate are plotted in Figure 2.12(a). The aggregate sample is a single lognormal distribution with a log mean K_z=1.3 md, as shown in Figure 2.12(b). Vertical permeability trends with respect to zone depth, top-to-bottom, east-west, north-south and core porosity are shown in Figures 2.13(a)-(e). No distinct geographic or geological trends are distinguishable from these graphs. Vertical permeability is moderately correlated with maximum permeability (correlation coefficient=0.450).

$$\log_{10}K_z = -.14 + .32 \log_{10}K_x \tag{2.4}$$

Figure 2.13(e) shows the correlation between vertical core permeability and core porosity (correlation coefficient =0.544).

$$\log_{10}K_z = .583 + 11.83\phi \tag{2.5}$$

Ample log data and a petrophysical summary was provided by Canadian Hunter (1994). Proper interpretation could not be made with these logs because of missing scales on the sheets provided. Only the water saturations listed in the petrophysical summary were used in this work. Table 2.3 summarizes the core and log data. The bulk water fraction is included to correlate the irreducible water saturation S_{wir} with porosity ϕ (Dewan, 1983, p276):

$$S_{wir} = \frac{0.0169}{\phi} \tag{2.6}$$

The rock compressibility coefficient[3] c_r is calculated with Hall's porosity correlation (Ahmed, 1989, p236) using average core porosities:

$$c_r = 6.37 \times 10^{-6} \text{ psi}^{-1} \tag{2.7}$$

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[3] The overburden weight may cause compaction in the bulk rock as production of fluids create an imbalance in stresses. As the rock compensates the stress imbalance by compaction, internal fluids get squeezed to higher pressures causing production to decline at slower rates.

Core Sample	08-07-37-7WS
Top (m)	2653.92
Bottom (m)	2659.00
KB (m)	1087.40

Depth (m)	Subsea Depth (m)	Subsea Depth (ft)	Thickness Δz (ft)	Porosity ϕ	K_x Maximum (md)	K_y 90 Degree (md)	K_z Vertical (md)
2653.92	1566.52	5139.50					
2654.09	1566.69	5140.06	0.56	2.70%	1.25	1.12	0.02
2654.38	1566.98	5141.01	0.95	6.80%	1.54	1.46	0.31
2654.62	1567.22	5141.80	0.79	2.30%	1.42	0.75	0.19
2654.85	1567.45	5142.55	0.75	2.70%	1.54	1.40	0.38
2655.09	1567.69	5143.34	0.79	1.10%	1.29	1.16	0.16
2655.36	1567.96	5144.23	0.89	3.90%	8.52	1.10	0.13
2655.65	1568.25	5145.18	0.95	5.30%	29.20	26.10	2.22
2655.82	1568.42	5145.73	0.56	5.90%	12.00	9.56	2.44
2656.32	1568.92	5147.38	1.64	6.40%	3.40	2.86	1.13
2656.72	1569.32	5148.69	1.31	5.40%	4.41	2.67	1.80
2657.11	1569.71	5149.97	1.28	3.60%	2.16		
2657.42	1570.02	5150.98	1.02	2.50%	2.61	2.17	0.77
2657.79	1570.39	5152.20	1.21	1.70%	0.41	0.35	0.13
2658.09	1570.69	5153.18	0.98	1.90%	7.66	2.62	0.25
2658.45	1571.05	5154.36	1.18	3.90%	0.15	0.11	0.01
2659.00	1571.60	5156.17	1.80	5.40%	0.06	0.06	0.01
ZONE			16.67	4.05%	1.94	1.31	0.23

Core Sample	14-07-37-7WS
Top (m)	2645.06
Bottom (m)	2653.51
KB (m)	1081.00

Depth (m)	Subsea Depth (m)	Subsea Depth (ft)	Thickness Δz (ft)	Porosity ϕ	K_x Maximum (md)	K_y 90 Degree (md)	K_z Vertical (md)
2645.06	1564.06	5131.43					
2645.38	1564.38	5132.48	1.05	6.40%	2.48	2.07	2.49
2645.49	1564.49	5132.84	0.36	7.50%	1090.00	194.00	23.50
2645.73	1564.73	5133.63	0.79	6.70%	3510.00		
2645.93	1564.93	5134.28	0.66	1.90%	2.47	2.47	0.63
2646.14	1565.14	5134.97	0.69	5.70%	5.21		
2646.60	1565.60	5136.48	1.51				
2646.78	1565.78	5137.07	0.59	3.60%	1.23	1.08	0.53
2647.05	1566.05	5137.96	0.89	5.40%	3.93	3.38	1.97
2647.27	1566.27	5138.68	0.72	4.10%	1.16	1.12	0.95
2647.43	1566.43	5139.21	0.52	5.60%	3.63	3.62	3.60
2647.60	1566.60	5139.76	0.56	8.50%	4.36	2.99	2.89
2647.83	1566.83	5140.52	0.75	7.70%	4.29	3.32	3.29
2648.00	1567.00	5141.08	0.56	7.50%	7.73	6.82	3.90
2648.26	1567.26	5141.93	0.85	11.30%	3.53	3.51	3.47
2648.46	1567.46	5142.59	0.66	6.10%	3.51	3.35	2.09
2648.60	1567.60	5143.04	0.46	7.10%	3.45	3.07	2.26
2648.76	1567.76	5143.57	0.52	8.60%	6.05	3.15	2.58
2648.94	1567.94	5144.16	0.59	5.90%	2.14	1.94	1.89
2649.01	1568.01	5144.39	0.23	5.00%	1.42	1.37	0.92
2649.31	1568.31	5145.37	0.98	6.90%	4.28	3.24	2.08
2649.48	1568.48	5145.93	0.56	6.40%	1.79	1.62	0.95
2649.72	1568.72	5146.72	0.79	6.50%	9.18	6.26	7.44
2649.94	1568.94	5147.44	0.72	7.70%	16.90	13.80	10.40
2650.11	1569.11	5148.00	0.56	7.50%	6.49	6.13	4.14
2650.39	1569.39	5148.92	0.92	6.70%	5.24	4.36	3.83
2650.65	1569.65	5149.77	0.85	4.90%	2.04	1.29	0.94
2650.89	1569.89	5150.56	0.79	7.00%	4.03	3.40	3.00
2651.10	1570.10	5151.25	0.69	8.80%	12.60	9.09	4.37
2651.32	1570.32	5151.97	0.72	9.60%	5.68	5.51	2.91
2651.51	1570.51	5152.59	0.62	8.10%	8.62	7.36	4.53
2651.86	1570.86	5153.74	1.15	7.50%	6.88	5.53	1.19
2652.11	1571.11	5154.56	0.82	7.40%	2.46	2.10	1.96
2652.34	1571.34	5155.31	0.75	7.90%	2.50	2.22	1.59
2652.71	1571.71	5156.53	1.21	7.60%	5.94	5.03	4.73
2652.87	1571.87	5157.05	0.52	9.20%	12.60	11.30	7.08
2653.04	1572.04	5157.61	0.56	10.70%	7.32	7.20	5.56
2653.21	1572.21	5158.17	0.56	9.20%	3.09	2.99	2.96
2653.32	1572.32	5158.53	0.36	8.70%	4.06	3.31	3.14
2653.37	1572.37	5158.69	0.16	9.20%	12.60	11.30	7.08
2653.51	1572.51	5159.15	0.46	6.30%	3.81	1.59	0.60
ZONE			27.72	7.09%	5.85	3.94	2.64

Table 2.2: Core Data

Core Sample	16-08-37-7W5
Top (m)	2608.00
Bottom (m)	2612.93
KB (m)	1076.10

Depth (m)	Subsea Depth (m)	Subsea Depth (ft)	Thickness Δz (ft)	Porosity ϕ	K_x Maximum (md)	K_y 90 Degree (md)	K_z Vertical (md)
2608.00	1531.90	5025.92					
2608.67	1532.57	5028.12	2.20	7.70%	4.80	4.67	0.89
2608.90	1532.80	5028.87	0.75	5.60%	0.55	0.40	0.24
2609.44	1533.34	5030.64	1.77	4.00%	2.24	2.23	1.33
2609.62	1533.52	5031.23	0.59	4.90%	15.30	2.44	1.67
2610.19	1534.09	5033.10	1.87	4.70%	2.65	2.03	0.49
2610.65	1534.55	5034.61	1.51	4.80%	2.17	0.94	0.27
2610.93	1534.83	5035.53	0.92	5.60%	3.85	1.96	0.66
2611.00	1534.90	5035.76	0.23	10.20%	0.23		
2611.44	1535.34	5037.20	1.44	6.60%	0.81	0.73	0.31
2612.13	1536.03	5039.47	2.26	10.20%			
2612.93	1536.83	5042.09	2.62	11.40%	0.27		
ZONE			16[illegible]7	7.25%	1.59	1.51	0.58

Core Sample	06-14-37-7W5
Top (m)	2557.40
Bottom (m)	2561.20
KB (m)	1061.60

Depth (m)	Subsea Depth (m)	Subsea Depth (ft)	Thickness Δz (ft)	Porosity ϕ	K_x Maximum (md)	K_y 90 Degree (md)	K_z Vertical (md)
2557.40	1495.80	4907.48					
2557.55	1495.95	4907.97	0.49	2.50%	4.79	3.93	1.14
2557.90	1496.30	4909.12	1.15	2.30%	11.80	8.61	1.28
2558.03	1496.43	4909.55	0.43	2.40%	10.30	6.21	0.92
2558.29	1496.69	4910.40	0.85	2.00%	1.97	1.84	0.88
2558.57	1496.97	4911.32	0.92	2.20%	34.50	33.30	1.14
2558.89	1497.29	4912.37	1.05	2.80%	39.90	29.10	0.90
2559.13	1497.53	4913.16	0.79	3.10%	1.13	1.00	0.22
2559.40	1497.80	4914.04	0.89	9.50%	1490.00	1220.00	12.90
ZONE			6.56	3.42%	15.07	12.09	1.17

Core Sample	06-15-37-7W5
Top (m)	2573.17
Bottom (m)	2579.11
KB (m)	1068.20

Depth (m)	Subsea Depth (m)	Subsea Depth (ft)	Thickness Δz (ft)	Porosity ϕ	K_x Maximum (md)	K_y 90 Degree (md)	K_z Vertical (md)
2573.17	1504.97	4937.57					
2573.40	1505.20	4938.32	0.75	3.90%	3.34	1.59	0.54
2573.70	1505.50	4939.30	0.98	5.70%	44.28	14.71	0.48
2574.06	1505.86	4940.49	1.18	3.20%	1.91	1.61	0.50
2574.34	1506.14	4941.40	0.92	4.70%	1275.62	510.00	0.10
2574.53	1506.33	4942.03	0.62	7.50%	316.95	72.04	10.67
2574.83	1506.63	4943.01	0.98	2.20%	0.93	0.84	0.32
2575.18	1506.98	4944.16	1.15	4.80%	20.65	2.42	0.28
2575.56	1507.36	4945.41	1.25	5.20%	3.37	2.44	0.32
2575.86	1507.66	4946.39	0.98	10.00%	1261.88	1213.80	2.61
2576.20	1508.00	4947.51	1.12	5.80%	5.30	4.34	1.58
2576.50	1508.30	4948.49	0.98	4.80%	3.39	3.09	1.85
2576.82	1508.62	4949.54	1.05	3.00%	1.39	1.35	0.62
2577.12	1508.92	4950.52	0.98	5.30%	6.47	6.27	0.31
2577.32	1509.12	4951.18	0.66	3.80%	0.53	0.46	0.38
2577.60	1509.40	4952.10	0.92	6.40%	8.33	8.13	0.36
2577.90	1509.70	4953.08	0.98	9.30%	38.47	35.86	9.93
2578.16	1509.96	4953.94	0.85	10.10%	17.52	10.17	5.56
2578.30	1510.10	4954.40	0.46	9.30%	0.32		
2578.63	1510.43	4955.48	1.08	9.40%	0.84	0.80	0.25
2578.81	1510.61	4956.07	0.59	13.30%	2.43	2.22	1.26
2579.11	1510.91	4957.05	0.98	9.90%	0.42	0.38	0.04
ZONE			19.49	6.32%	7.27	5.58	0.69

Table 2.2: Core Data (Continued)

Core Sample	08-17-37-7W5
Top (m)	2598.55
Bottom (m)	2602.69
KB (m)	1062.50

Depth (m)	Subsea Depth (m)	Subsea Depth (ft)	Thickness Δz (ft)	Porosity ϕ	K_x Maximum (md)	K_y 90 Degree (md)	K_z Vertical (md)
2598.55	1536.05	5039.53					
2598.83	1536.33	5040.45	0.92	2.40%	1.53	1.29	0.47
2599.08	1536.58	5041.27	0.82	2.60%	1.81	1.38	0.57
2599.37	1536.87	5042.22	0.95	1.80%	1.01	0.80	0.45
2599.61	1537.11	5043.01	0.79	2.10%	2.17	1.78	0.24
2600.05	1537.55	5044.46	1.44	7.10%	3.55	2.97	2.23
2600.25	1537.75	5045.11	0.66	7.10%	56.50	38.00	1.45
2600.66	1538.16	5046.46	1.35	7.90%	1000.00	5.01	2.18
2600.85	1538.35	5047.08	0.62	6.60%	1.96	1.55	3.65
2601.14	1538.64	5048.03	0.95	8.90%	63.20	45.90	5.14
2601.33	1538.83	5048.65	0.62	5.50%	2.56	2.37	1.58
2601.48	1538.98	5049.15	0.49	8.80%	12.10	8.44	7.25
2601.73	1539.23	5049.97	0.82	6.30%	3.45	3.16	3.30
2601.90	1539.40	5050.52	0.56	7.10%	5.37	3.22	1.92
2602.20	1539.70	5051.51	0.98	2.20%	8.55	7.41	7.86
2602.48	1539.98	5052.43	0.92	8.60%	13.70	10.30	10.40
2602.69	1540.19	5053.12	0.69	5.50%	1.93	1.46	0.39
ZONE			13.58	5.64%	6.77	3.85	1.76

Core Sample	06-13-37-8W5
Top (m)	2683.50
Bottom (m)	2686.33
KB (m)	1089.00

Depth (m)	Subsea Depth (m)	Subsea Depth (ft)	Thickness Δz (ft)	Porosity ϕ	K_x Maximum (md)	K_y 90 Degree (md)	K_z Vertical (md)
2683.50	1594.50	5231.30					
2683.64	1594.64	5231.76	0.46	1.80%	3.53	1.86	0.29
2683.75	1594.75	5232.12	0.36	3.50%	0.78		
2683.87	1594.87	5232.51	0.39	5.70%	1540.00	1090.00	2.83
2684.08	1595.08	5233.20	0.69	4.40%	5.70	3.72	1.41
2684.17	1595.17	5233.50	0.30	4.00%	0.60		
2684.39	1595.39	5234.22	0.72	5.40%	5.46	5.13	1.02
2684.60	1595.60	5234.91	0.69	5.70%	4.85	4.56	2.68
2684.74	1595.74	5235.37	0.46	5.80%	18.00		
2685.01	1596.01	5236.25	0.89	8.90%	1360.00	556.00	3.00
2685.16	1596.16	5236.75	0.49	6.30%	27.00		
2685.48	1596.48	5237.80	1.05	5.00%	2.77	2.63	1.67
2685.51	1596.51	5237.89	0.10				
2685.79	1596.79	5238.81	0.92	4.70%	2.42	2.11	2.06
2685.89	1596.89	5239.14	0.33	2.90%	1.03		
2686.05	1597.05	5239.67	0.52	3.80%	8.91	7.21	1.54
2686.17	1597.17	5240.06	0.39	4.40%	0.65		
2686.33	1597.33	5240.58	0.52	4.70%	1.40	1.14	0.61
ZONE			9.28	5.09%	6.64	9.23	1.41

Core Sample	08-14-37-8W5
Top (m)	2758.19
Bottom (m)	2760.56
KB (m)	1100.00

Depth (m)	Subsea Depth (m)	Subsea Depth (ft)	Thickness Δz (ft)	Porosity ϕ	K_x Maximum (md)	K_y 90 Degree (md)	K_z Vertical (md)
2758.19	1658.19	5440.26					
2758.40	1658.40	5440.94	0.69	3.70%	3.85	3.82	1.38
2758.75	1658.75	5442.09	1.15	4.60%	2.51	2.51	2.34
2758.96	1658.96	5442.78	0.69	4.90%	1.96	1.69	1.87
2759.32	1659.32	5443.96	1.18	5.60%	4.64	4.34	3.80
2759.60	1659.60	5444.88	0.92	5.60%	3.70	3.56	2.89
2759.86	1659.86	5445.73	0.85	6.30%	1.97	1.96	0.88
2760.07	1660.07	5446.42	0.69	6.90%	3.06	2.67	2.52
2760.26	1660.26	5447.05	0.62	6.10%	1.08	1.03	0.76
2760.56	1660.56	5448.03	0.98	5.20%	0.82	0.73	0.62
ZONE			7.78	5.40%	2.29	2.15	1.60

Table 2.2: Core Data (Continued)

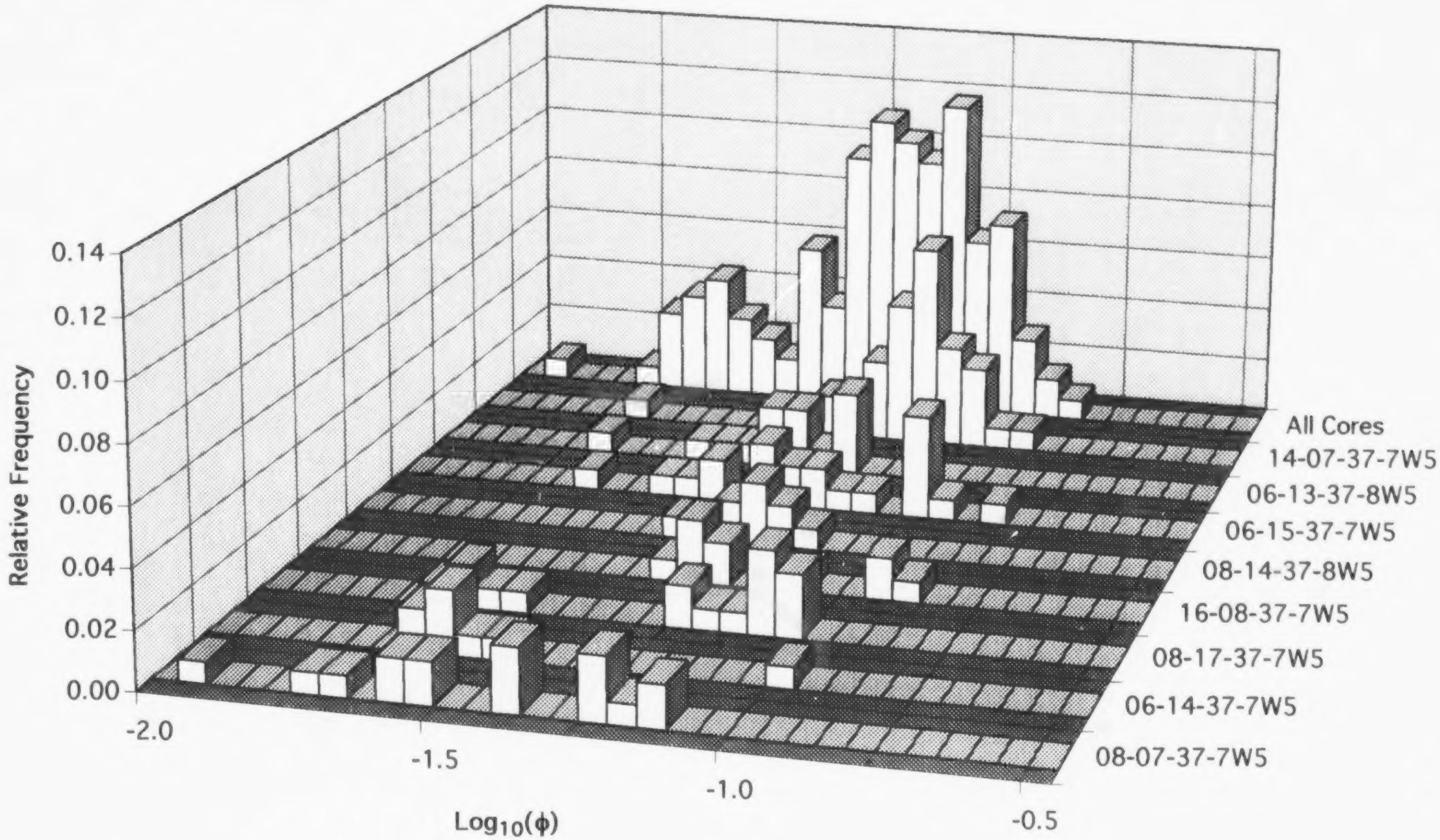

Figure 2.6(a): Core Porosity ϕ Histogram

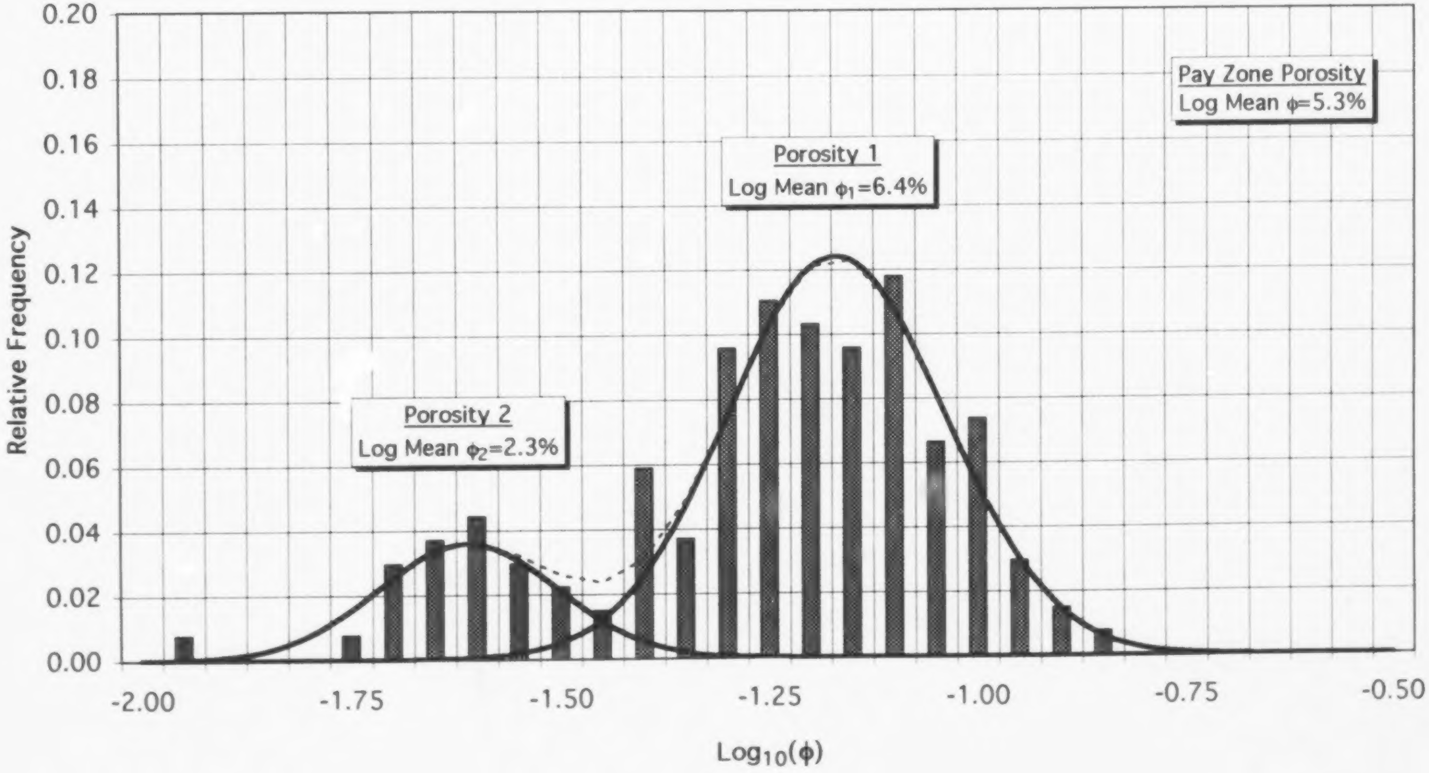

Figure 2.6(b): Core Porosity Histogram (Lognormal Segmentation)

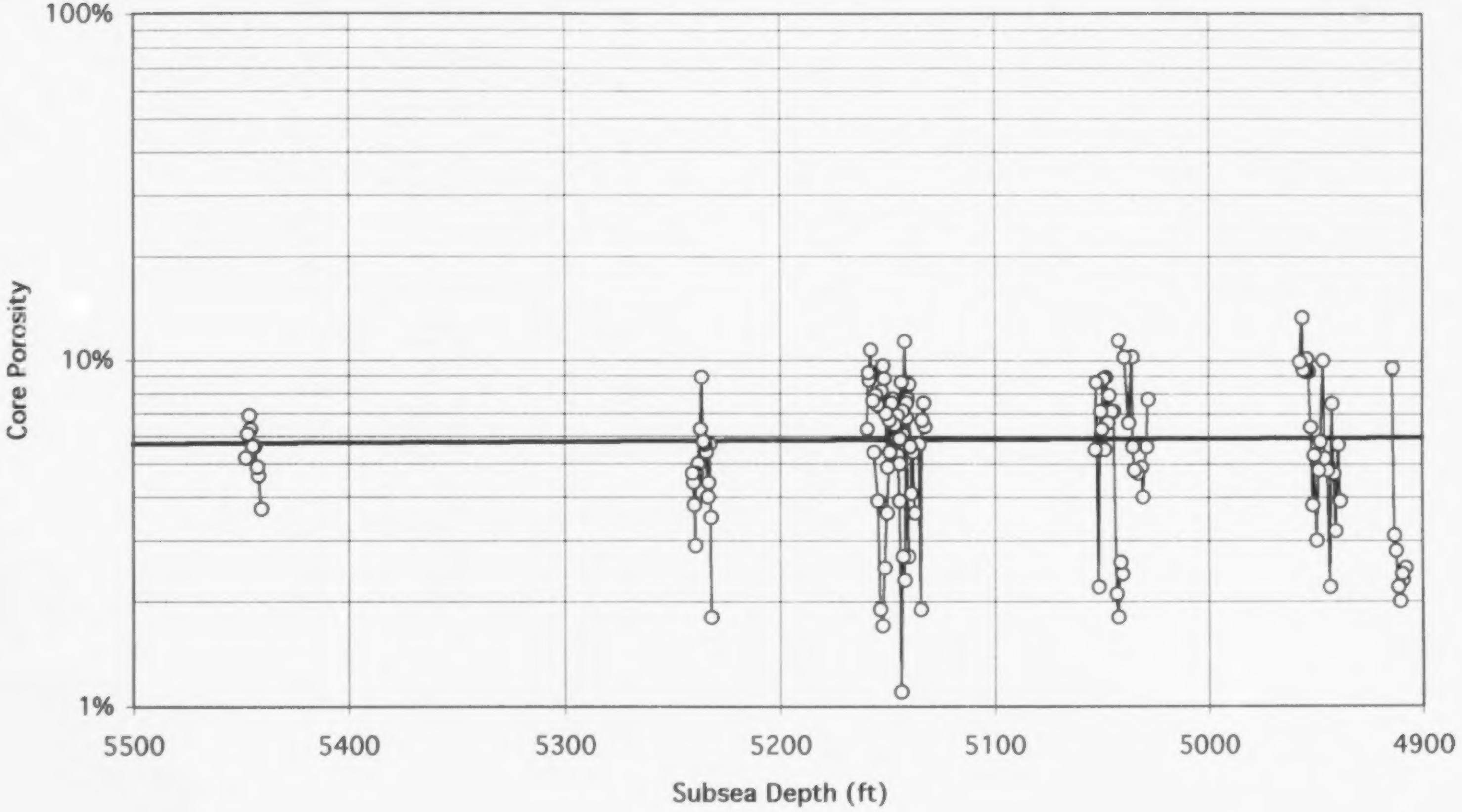

Figure 2.7(a): Core Porosity Depth Trend

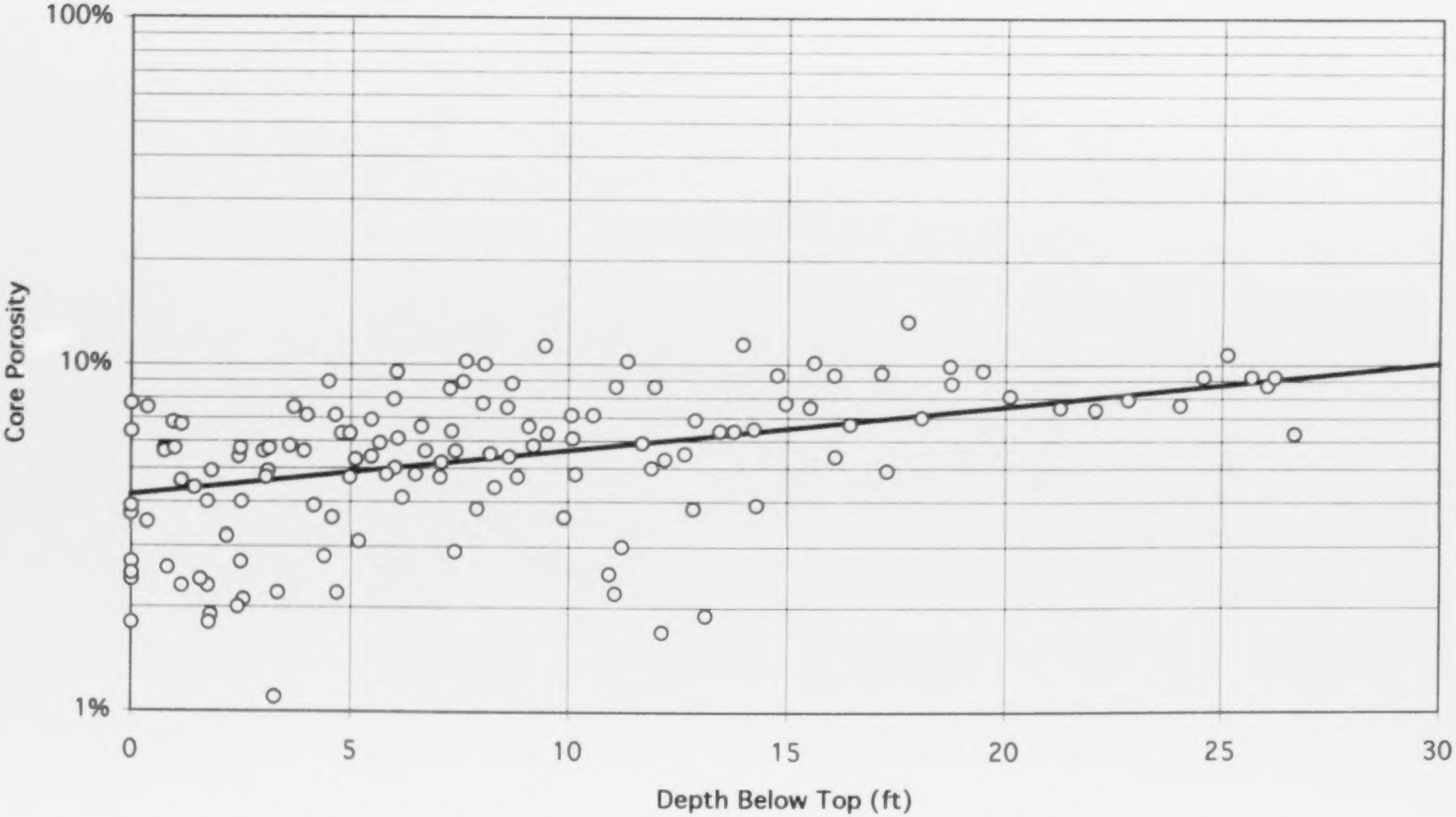

Figure 2.7(b): Core Porosity Top-to-Bottom Trend

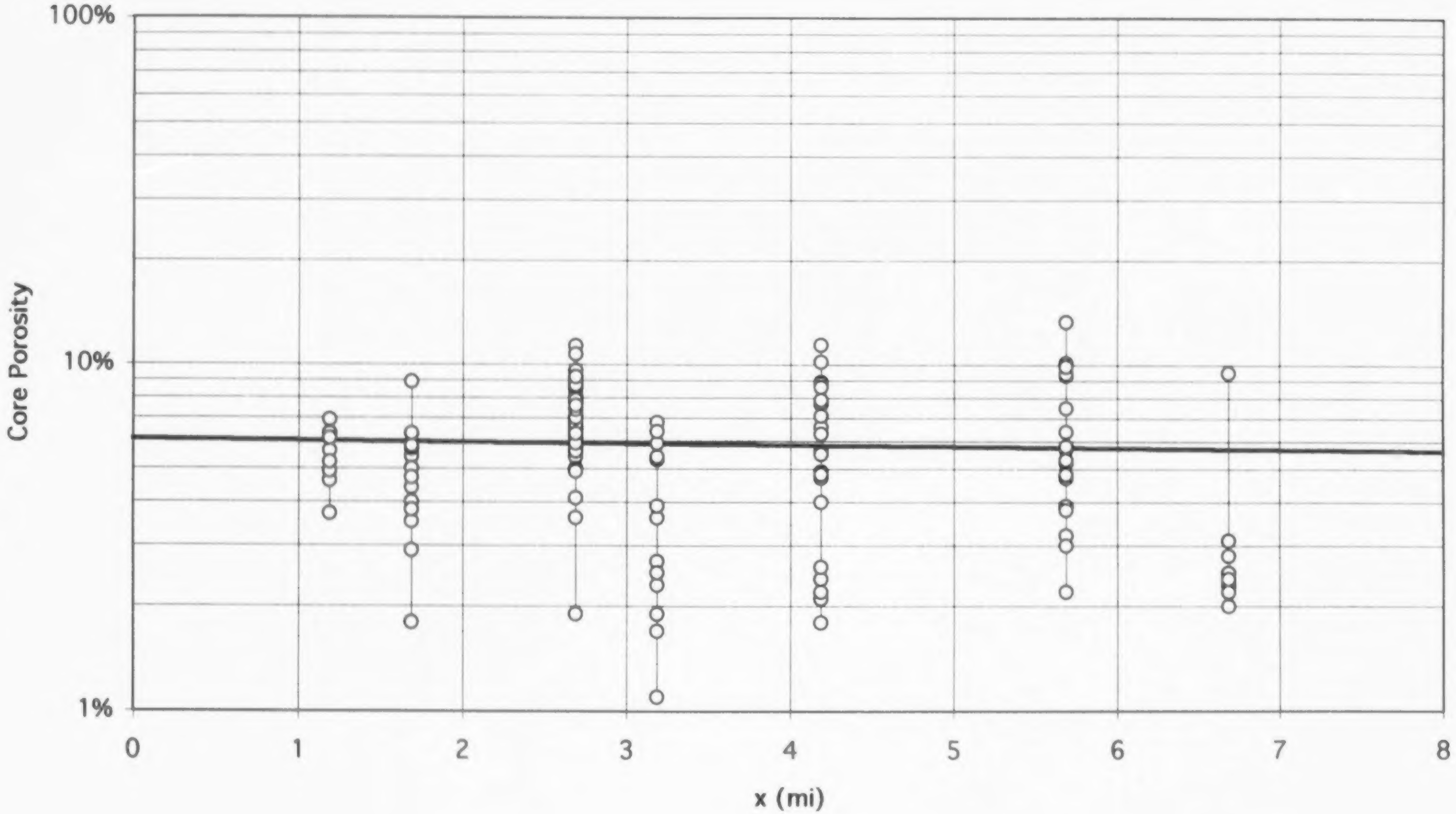

Figure 2.7(c): Core Porosity East-West Trend

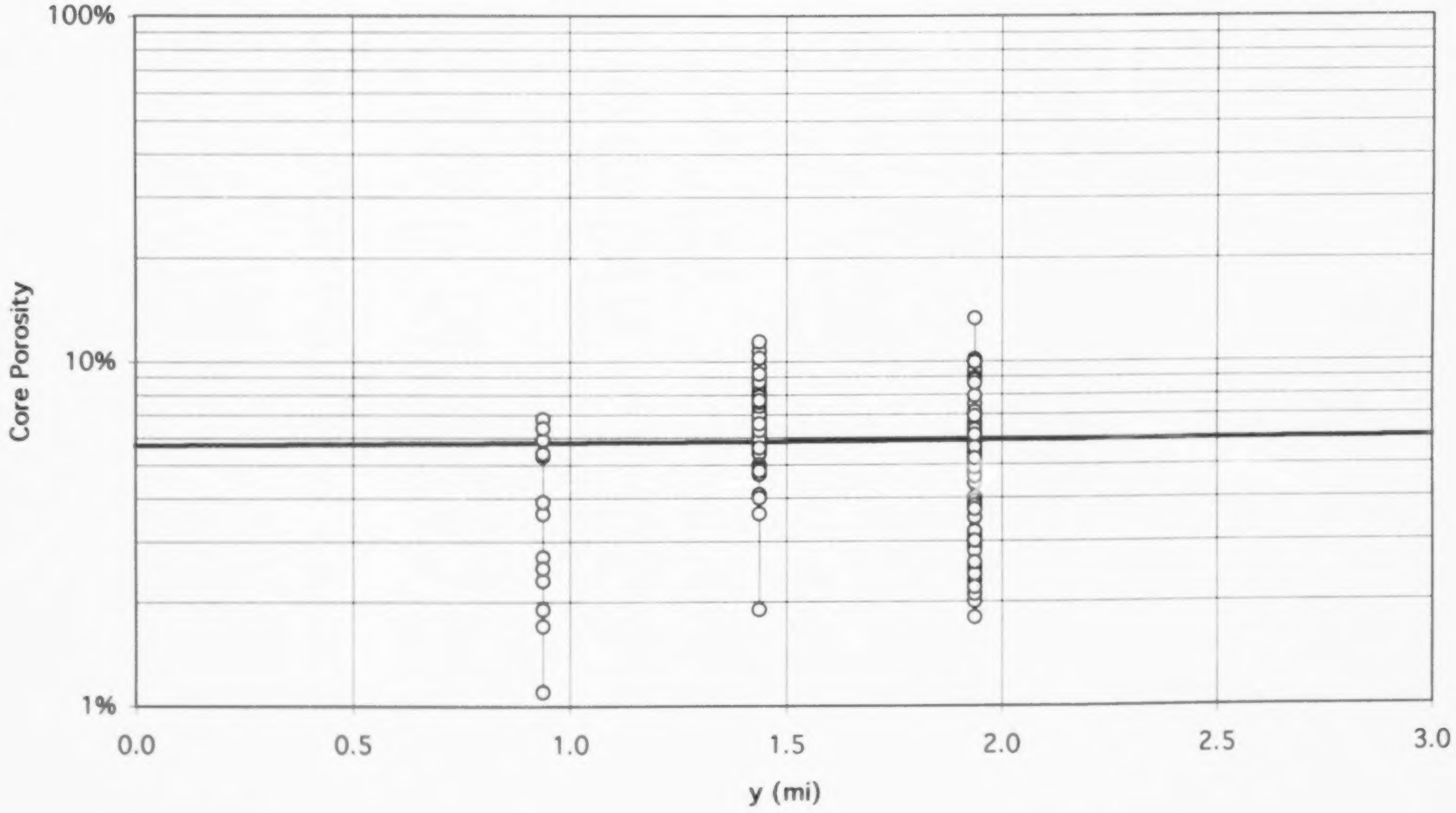

Figure 2.7(d): Core Porosity North-South Trend

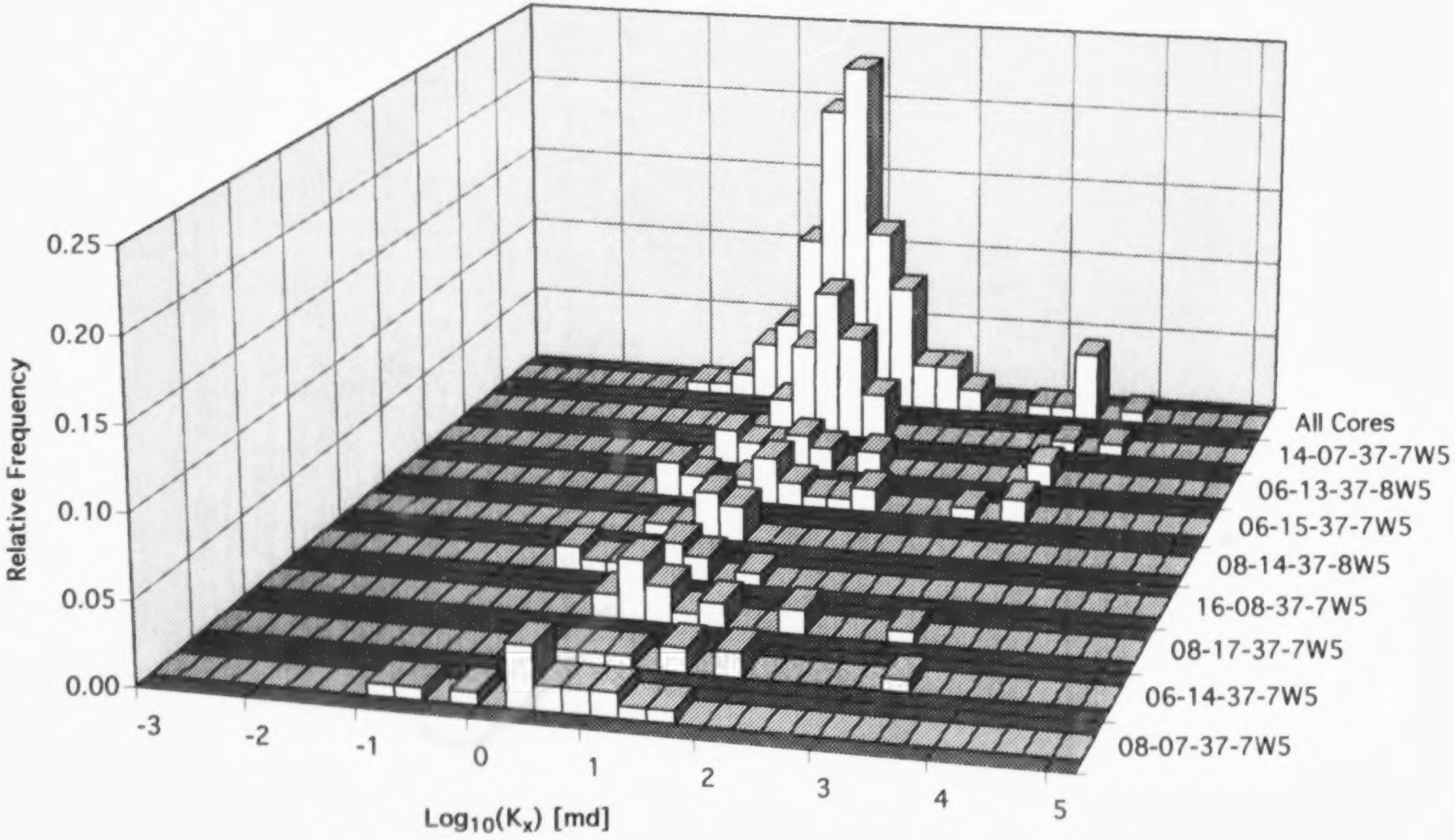

Figure 2.8(a): Core Maximum Permeability K_x Histogram

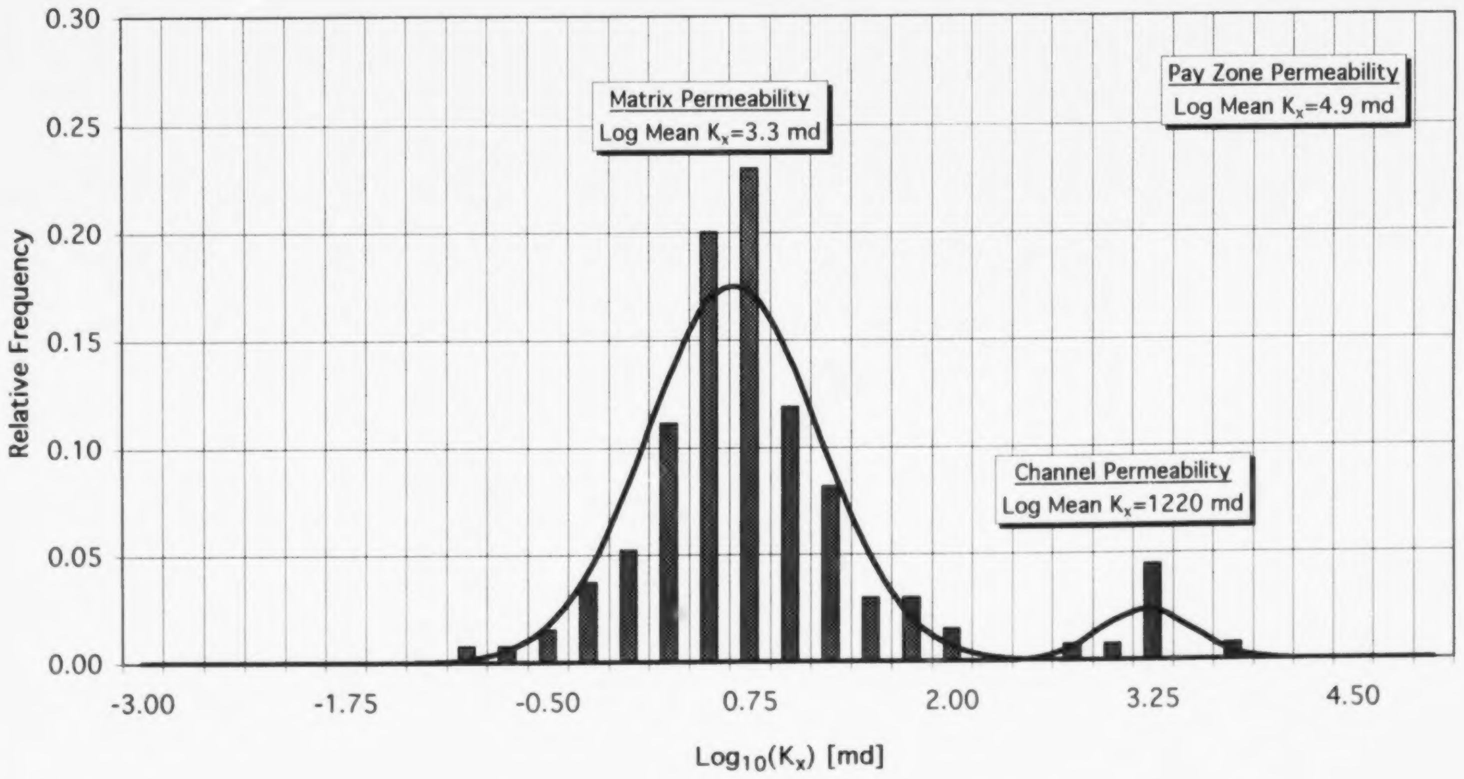

Figure 2.8(b): Core Maximum Permeability K_x Histogram (Lognormal Segmentation)

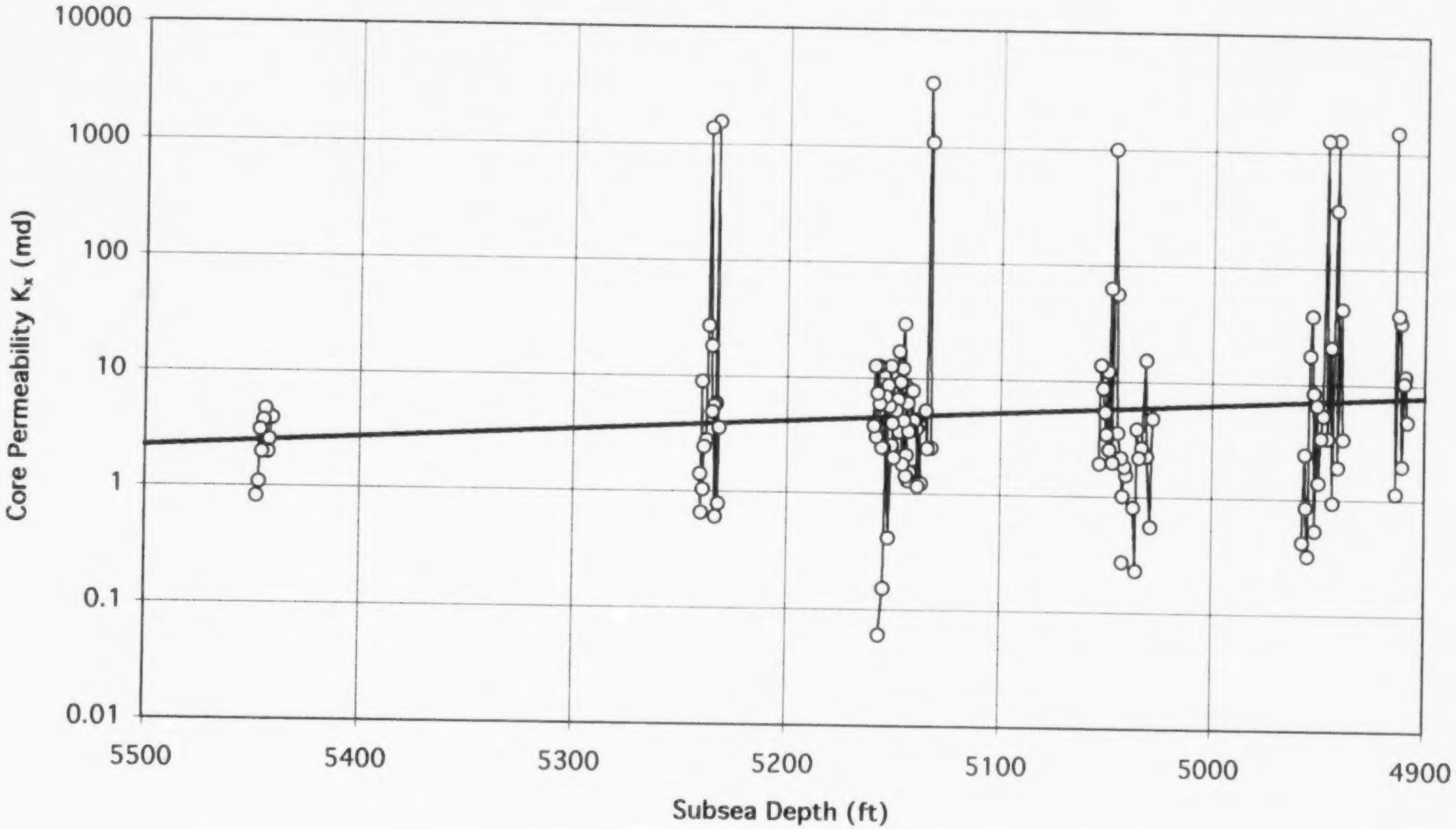

Figure 2.9(a): Core Maximum Permeability K_x vs Depth

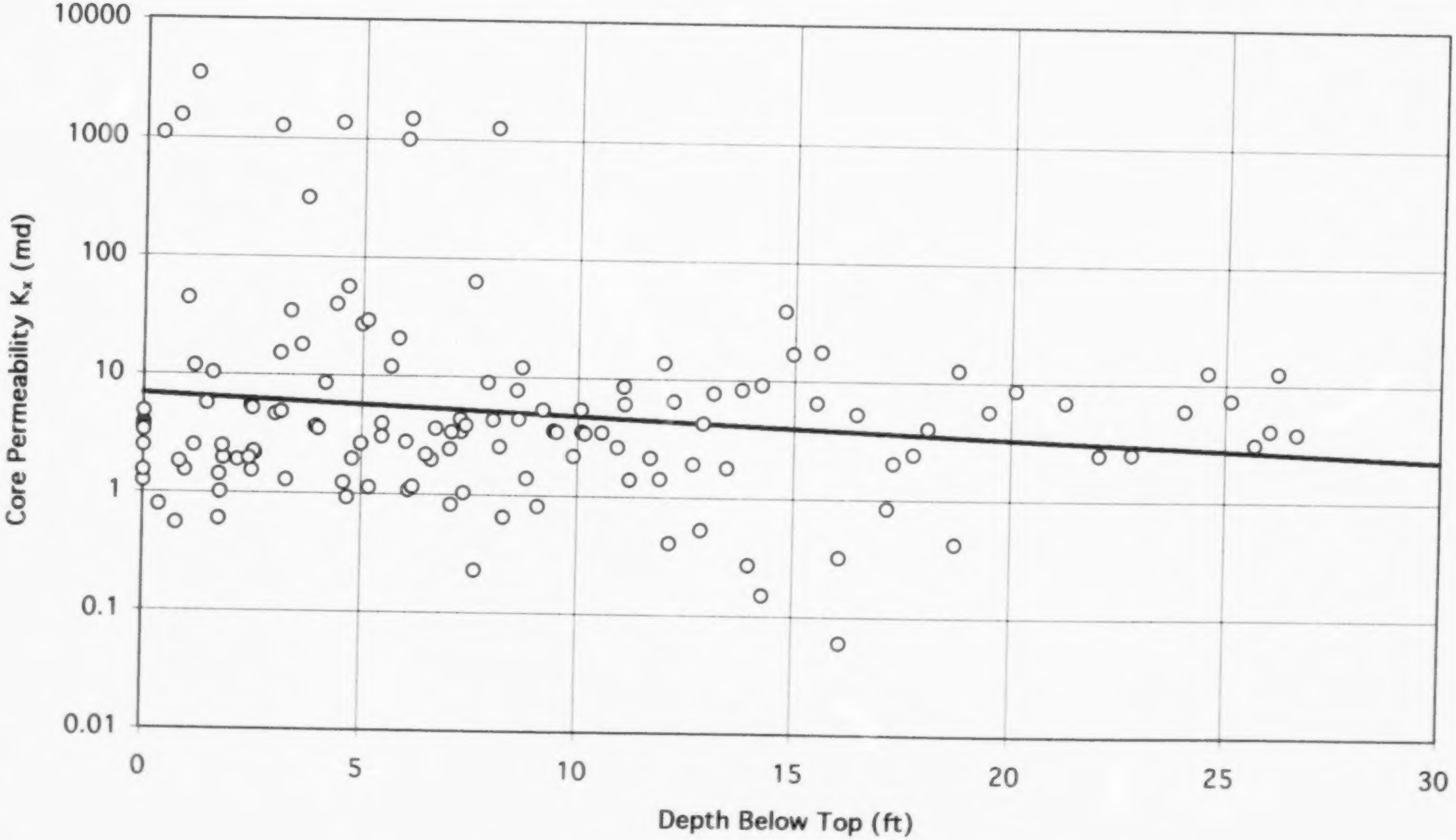

Figure 2.9(b): Core Maximum Permeability K_x Vertical Trend

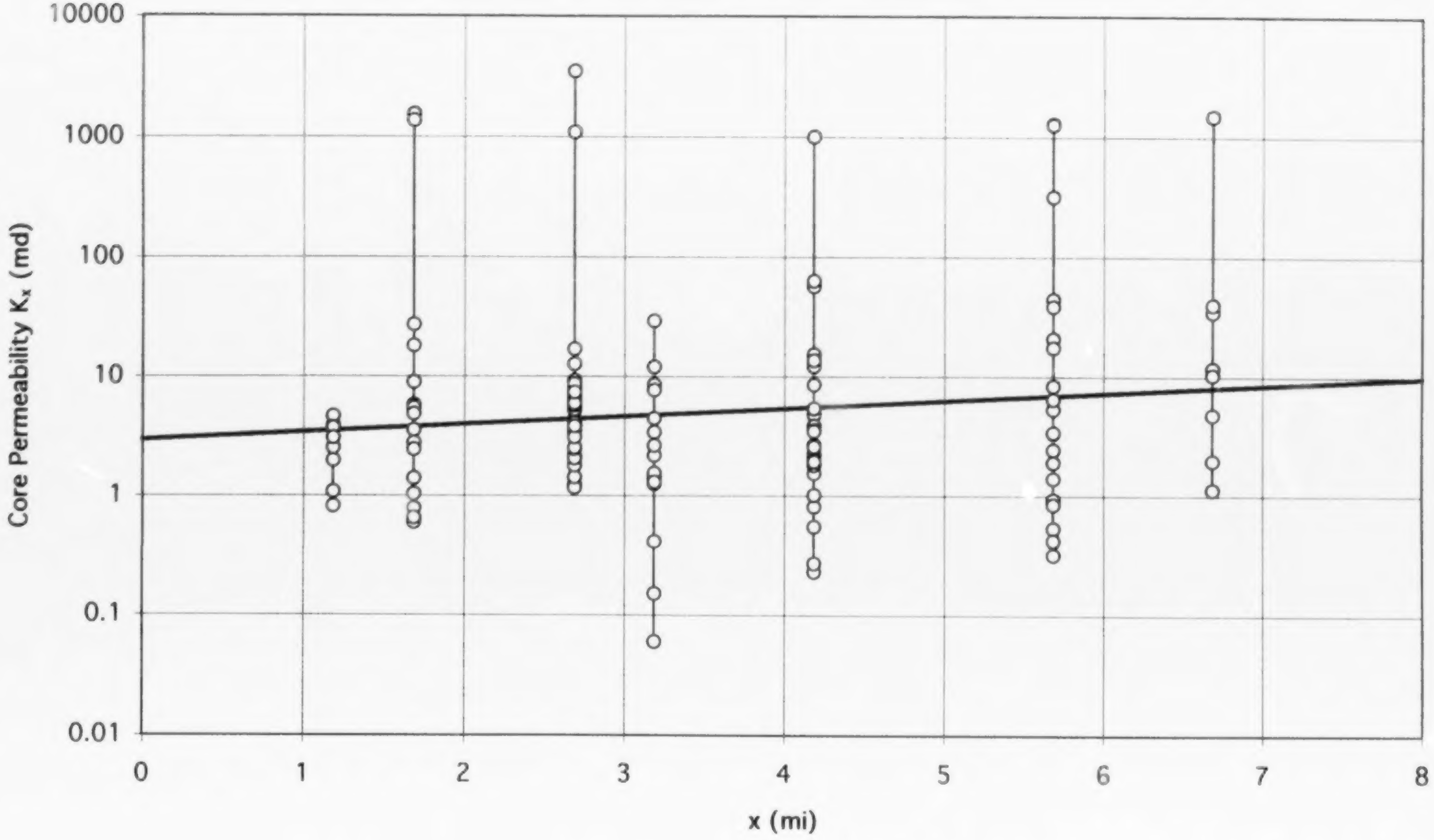

Figure 2.9(c): Core Maximum Permeability K_x East-West Trend

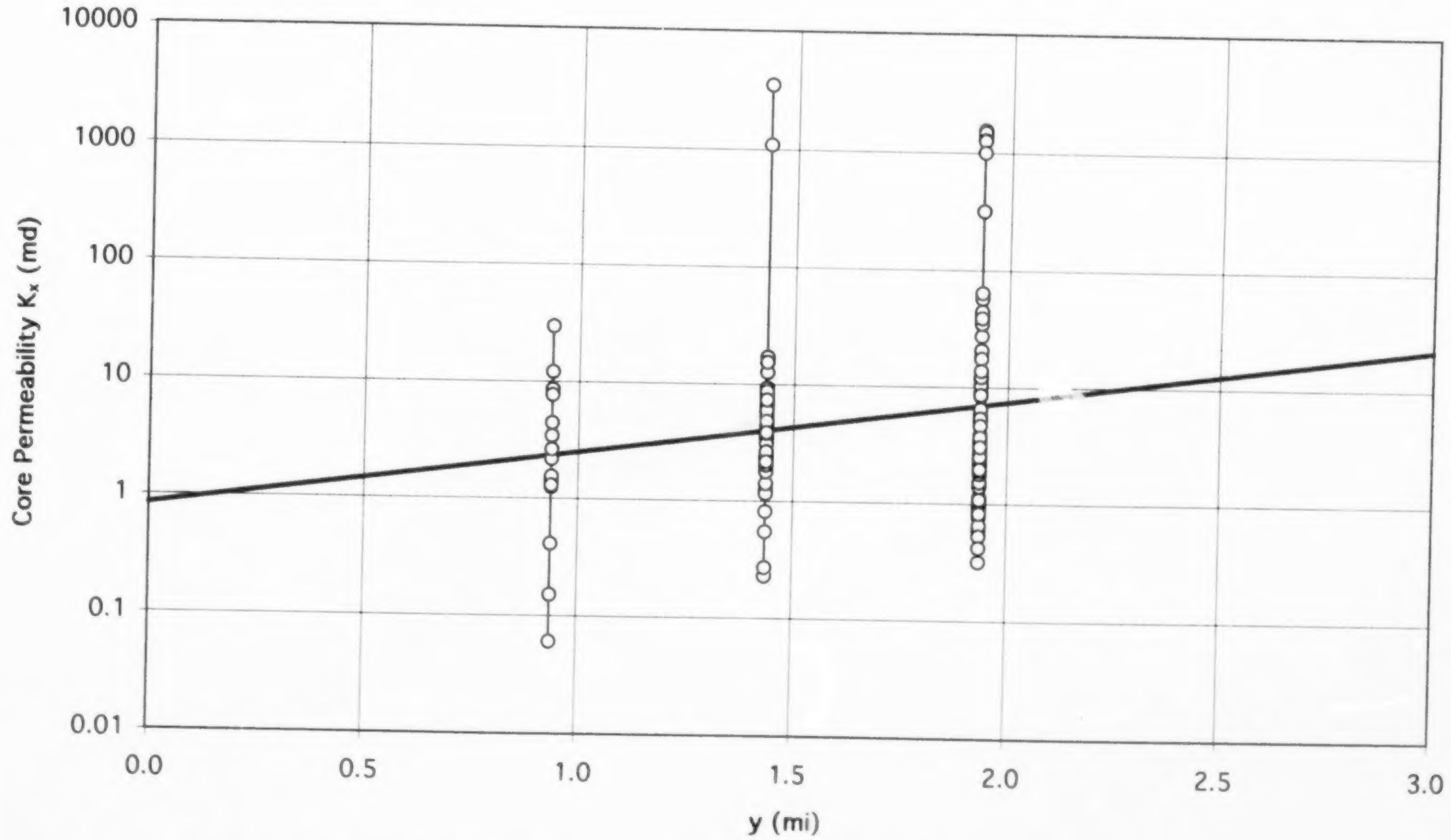

Figure 2.9(d): Core Maximum Permeability K_x North-South Trend

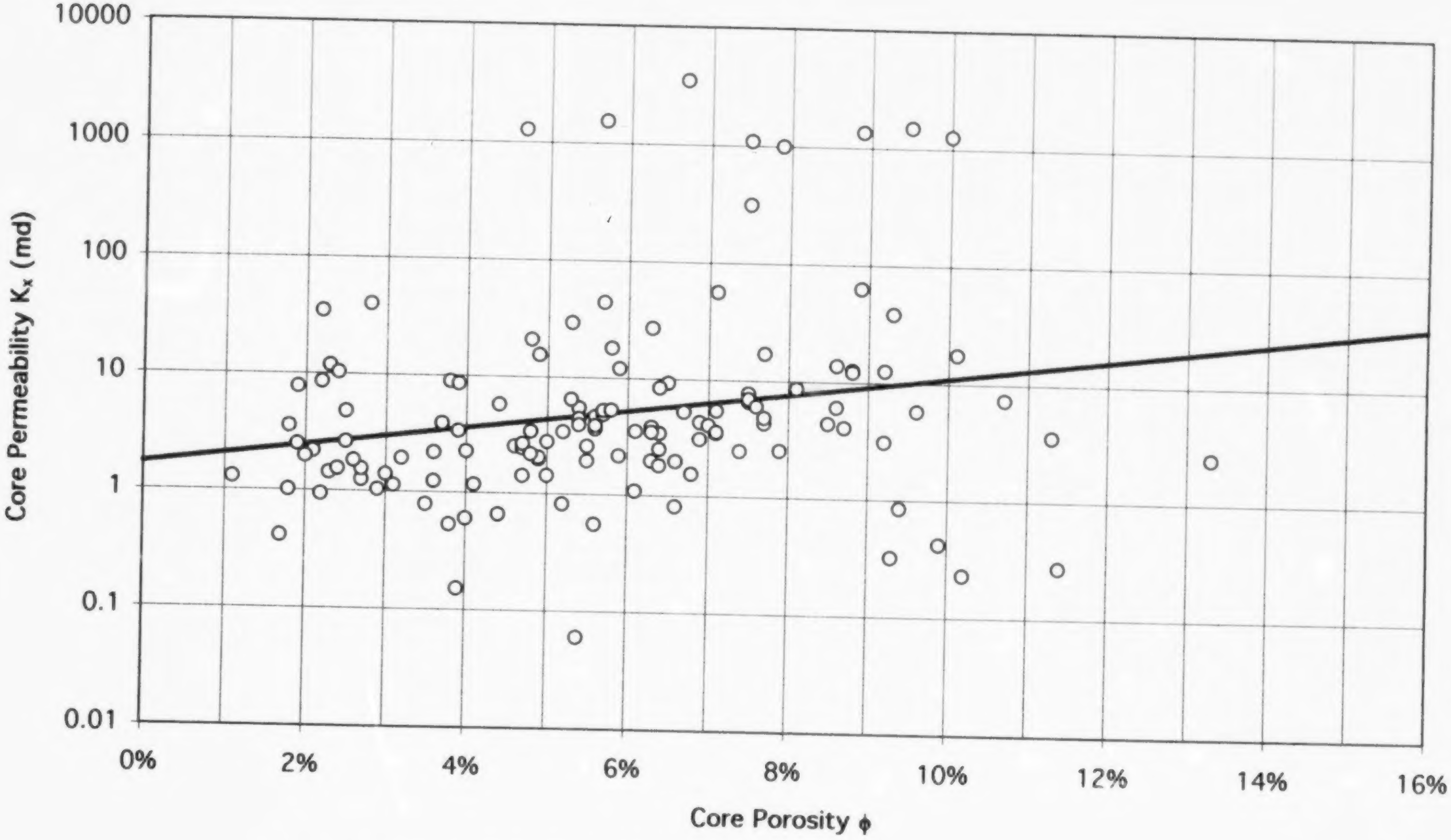

Figure 2.9(e): Core Maximum Permeability K_x vs Core Porosity ϕ

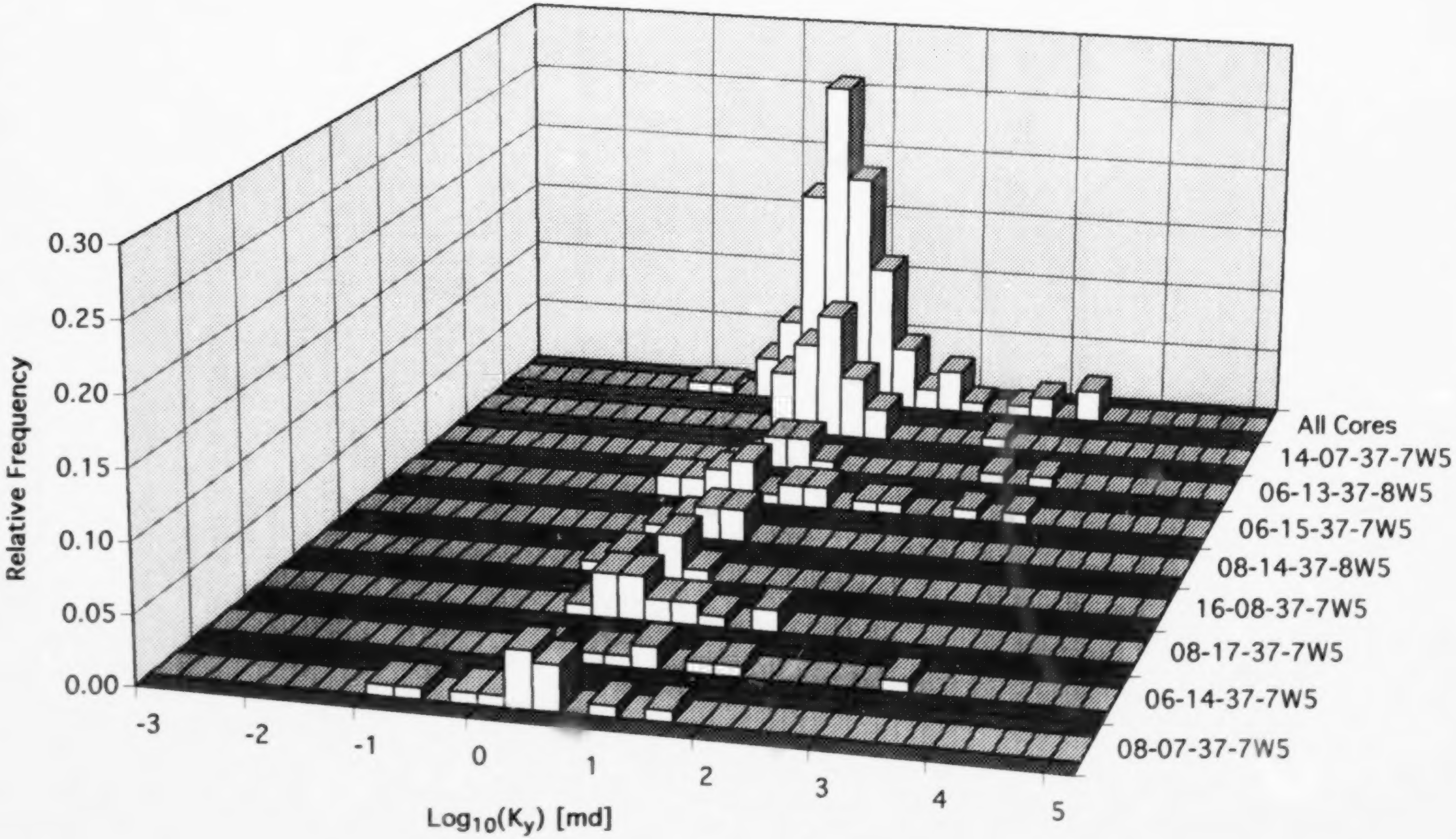

Figure 2.10(a): Core 90-Degree Permeability K_y Histogram

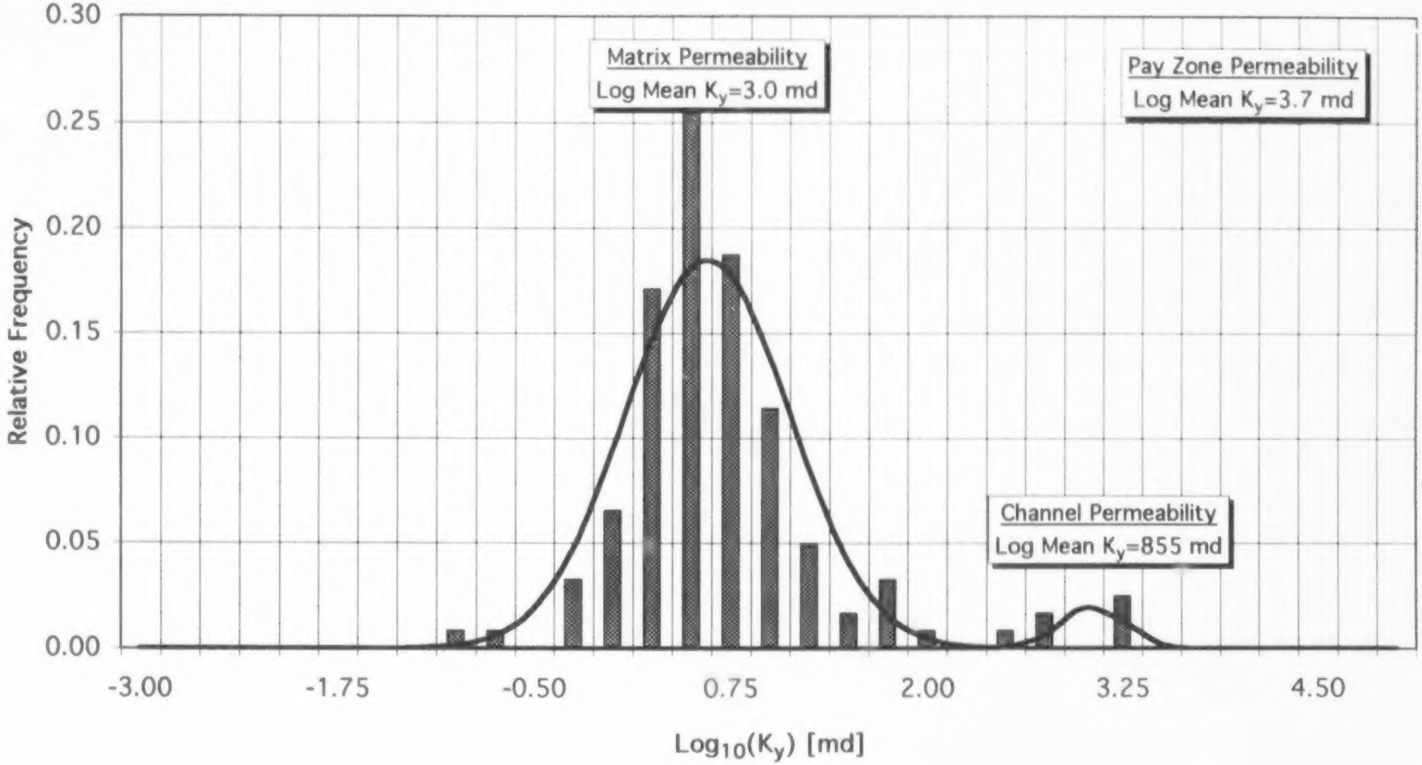

Figure 2.10(b): Core 90 Degree Permeability K_y Histogram
(Lognormal Segmentation)

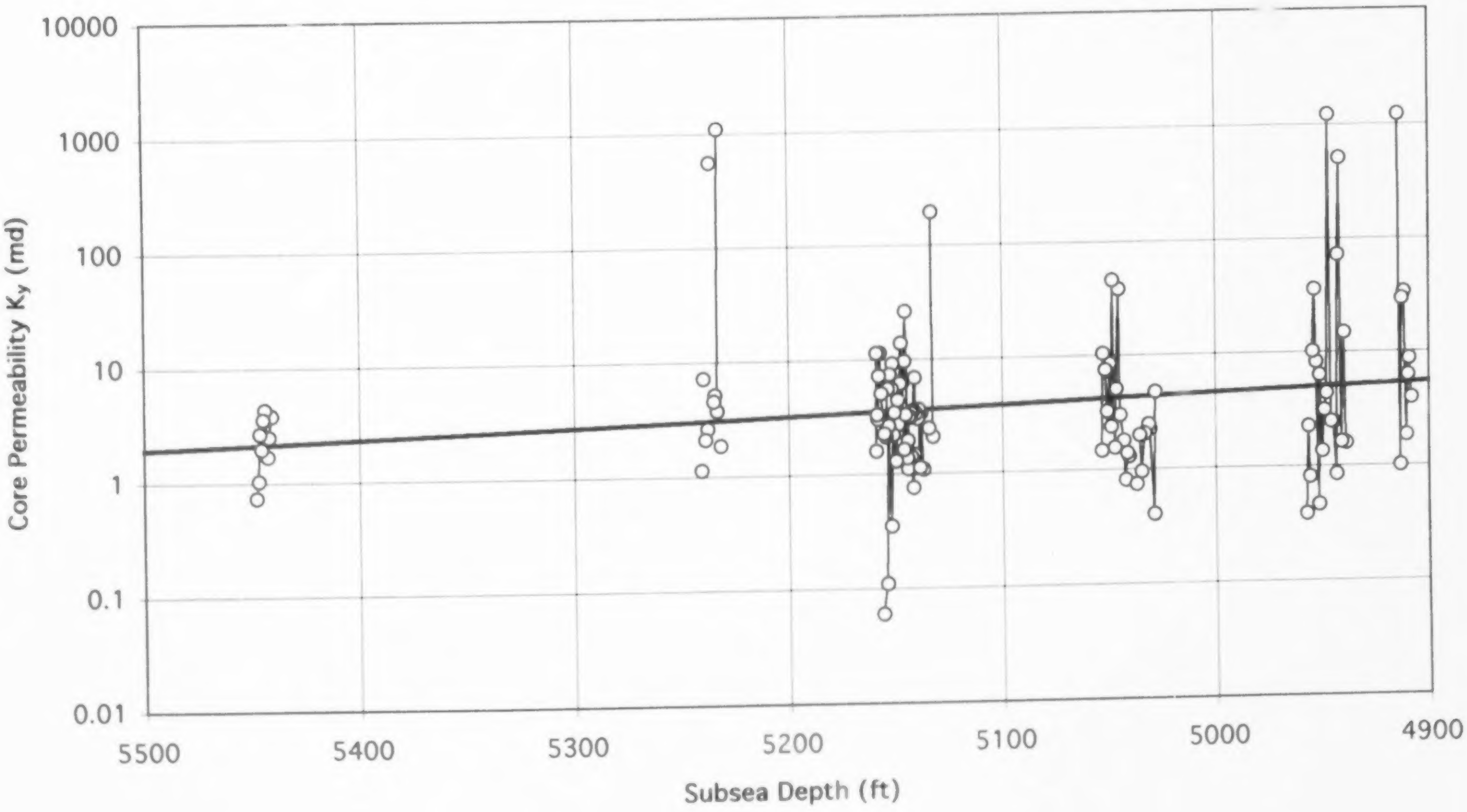

Figure 2.11(a): Core 90 Degree Permeability K_y vs Depth

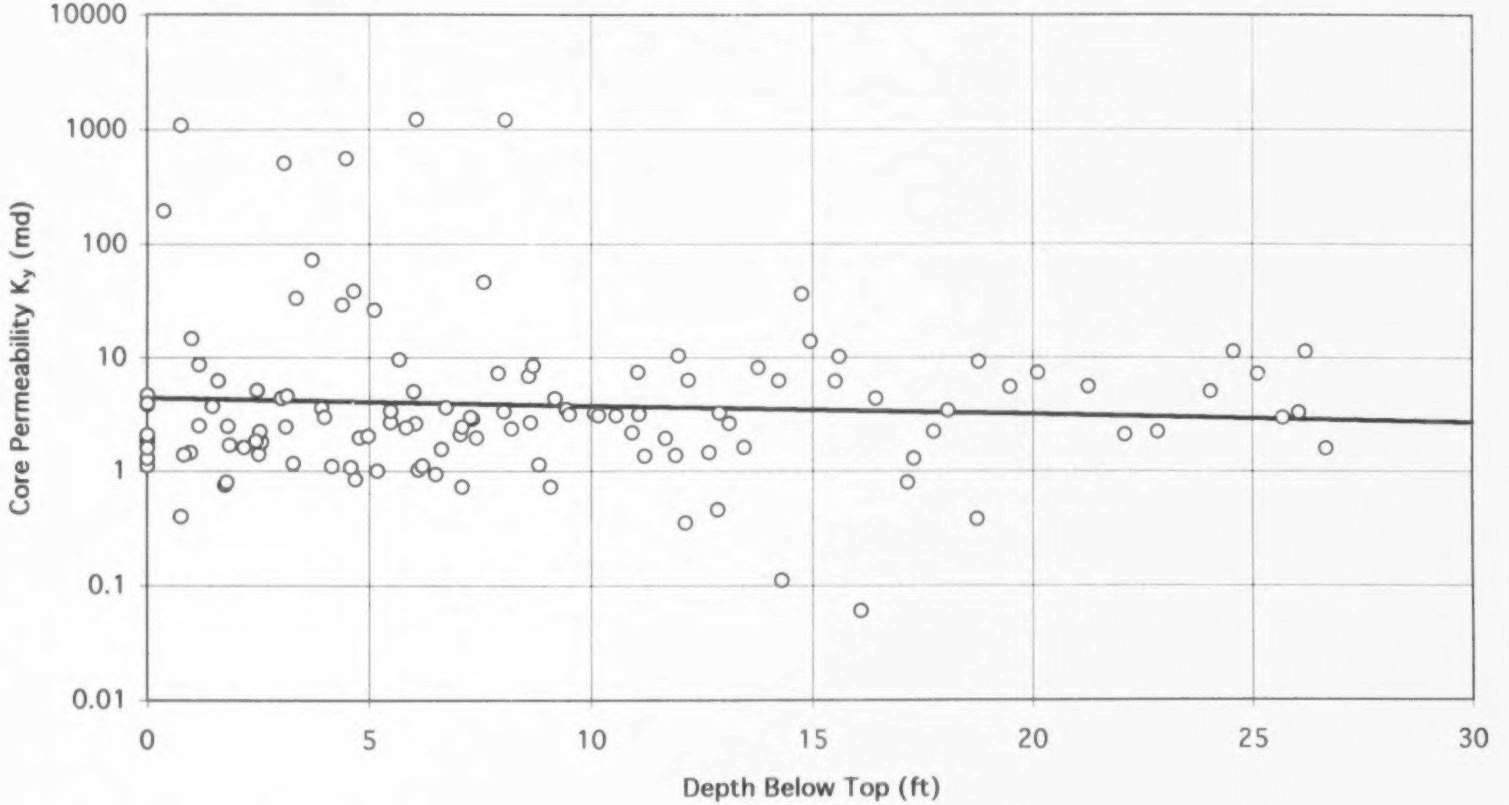

Figure 2.11(b): Core 90 Degree Permeability K_y Vertical Trend

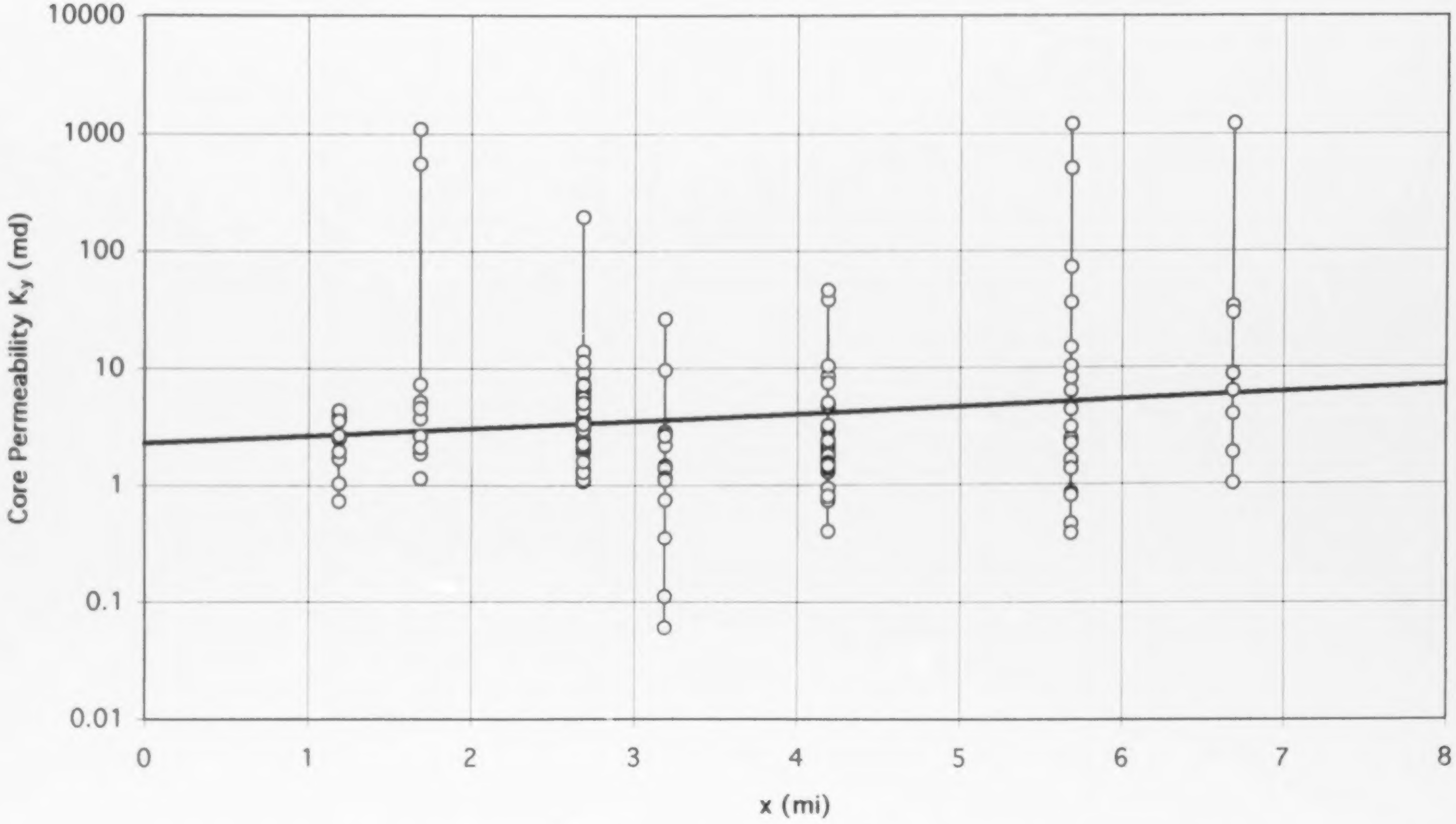

Figure 2.11(c): Core 90 Degree Permeability K_y East-West Trend

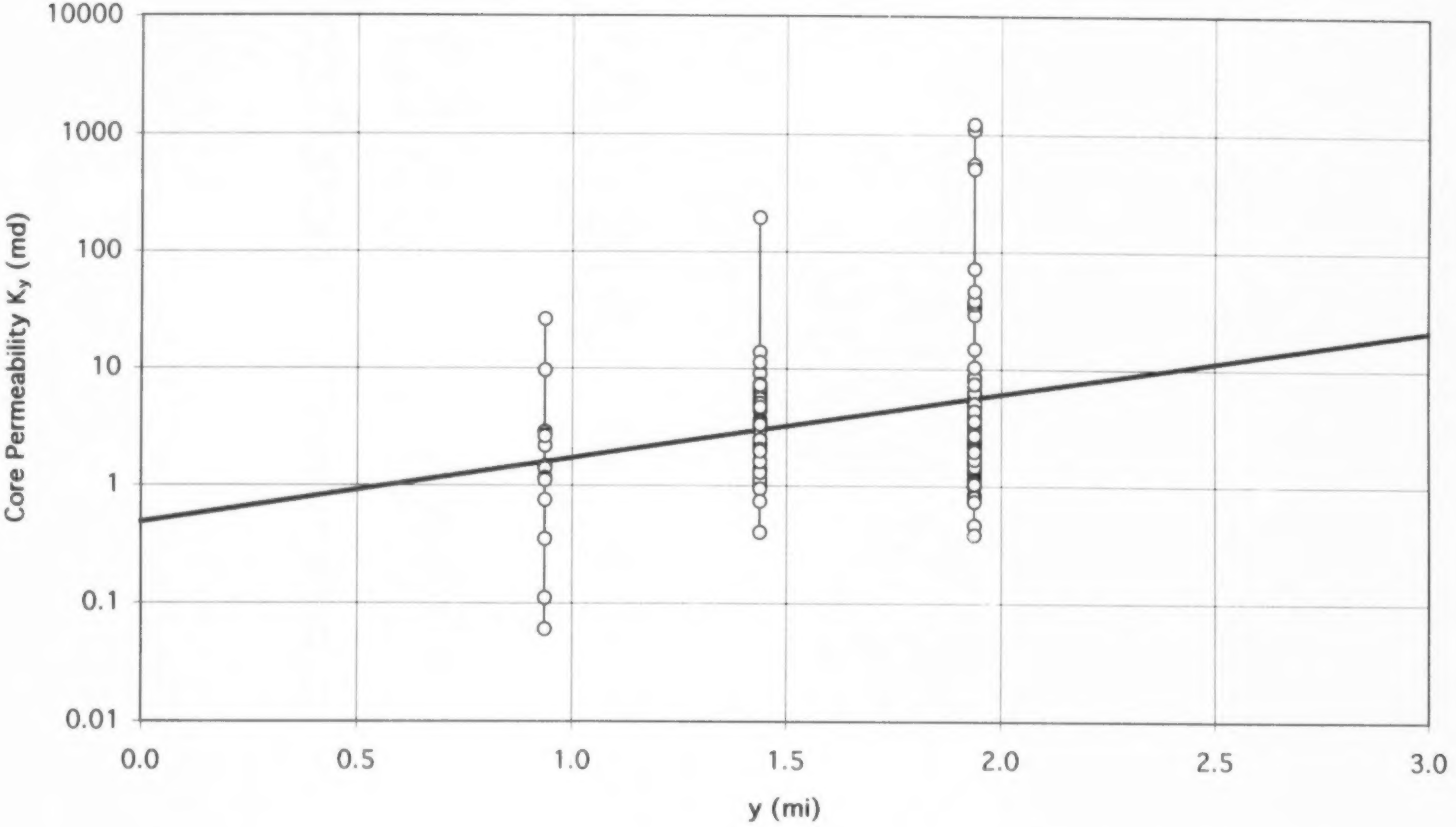

Figure 2.11(d): Core 90 Degree Permeability K_y North-South Trend

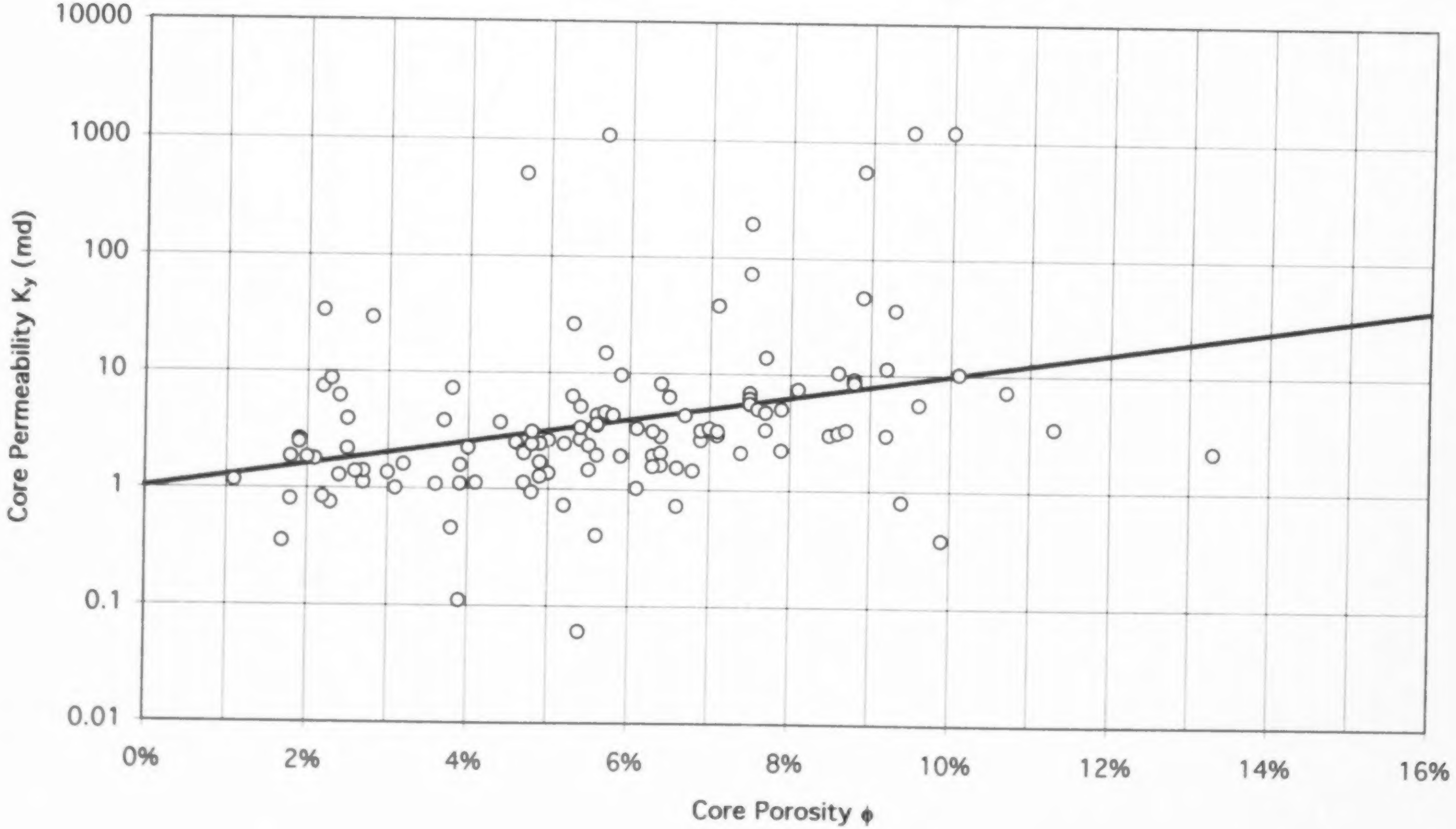

Figure 2.11(e): Core 90 Degree Permeability K_y vs Core Porosity ϕ

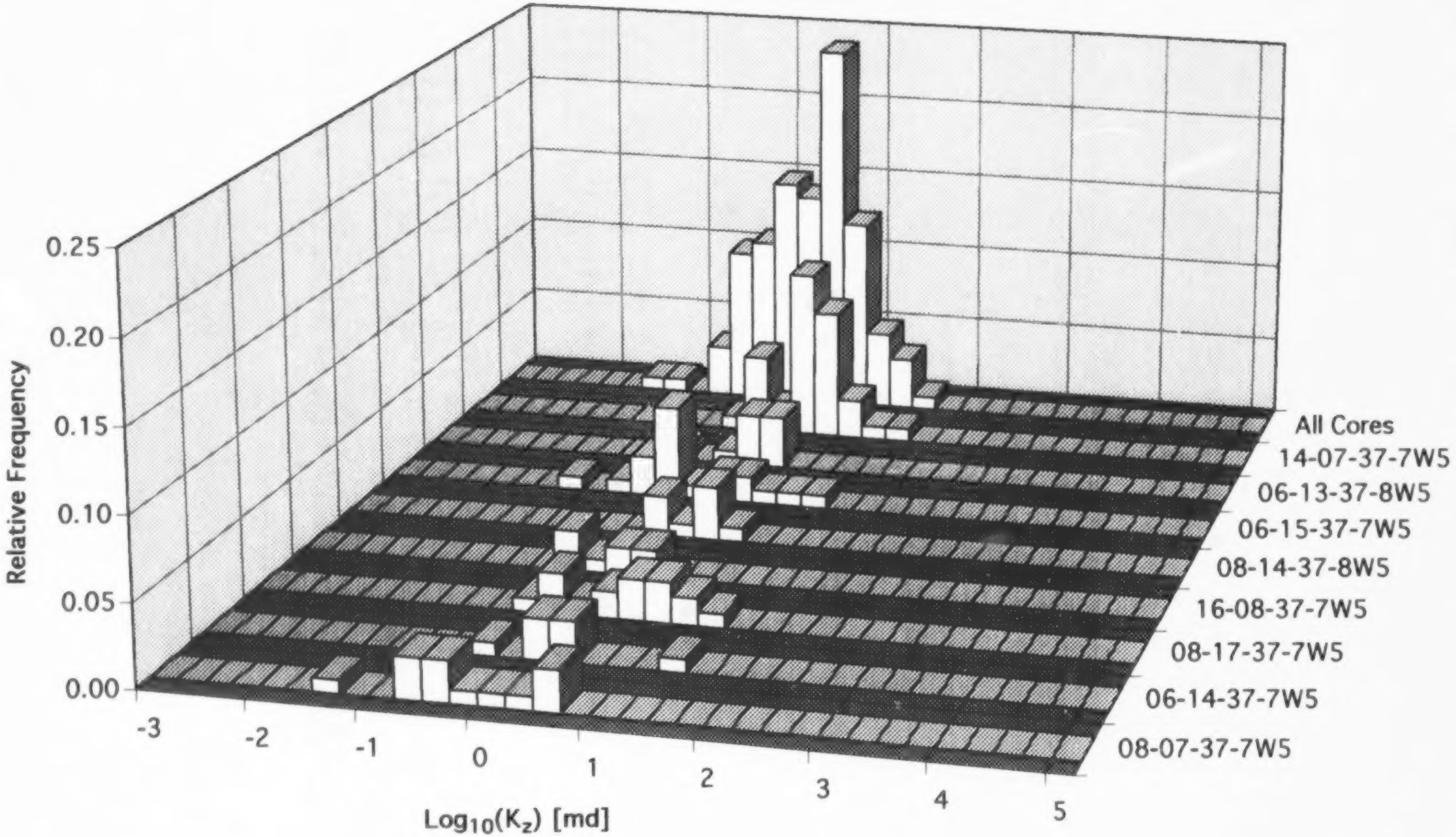

Figure 2.12(a): Core Vertical Permeability K_z Histogram

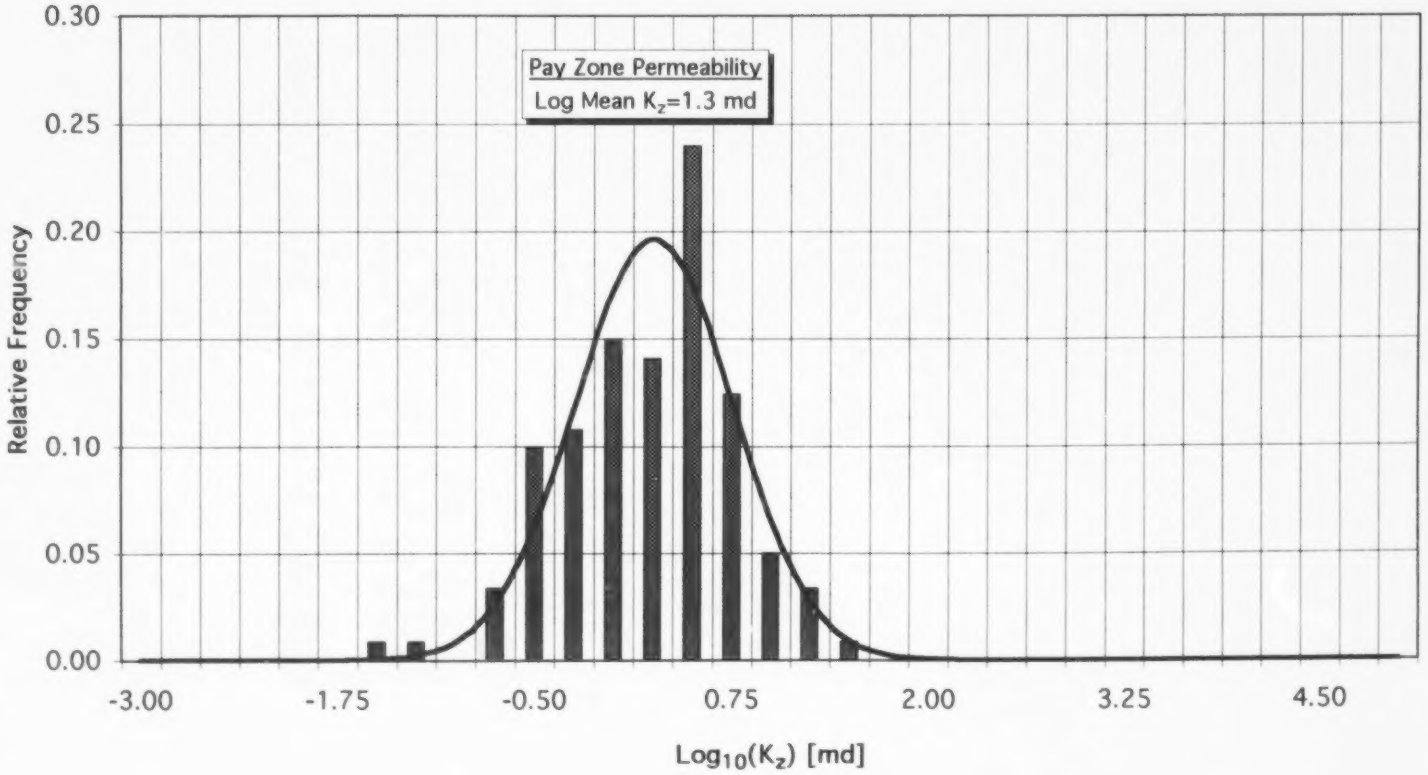

Figure 2.12(b): Core Vertical Permeability K_z Histogram (Lognormal Segmentation)

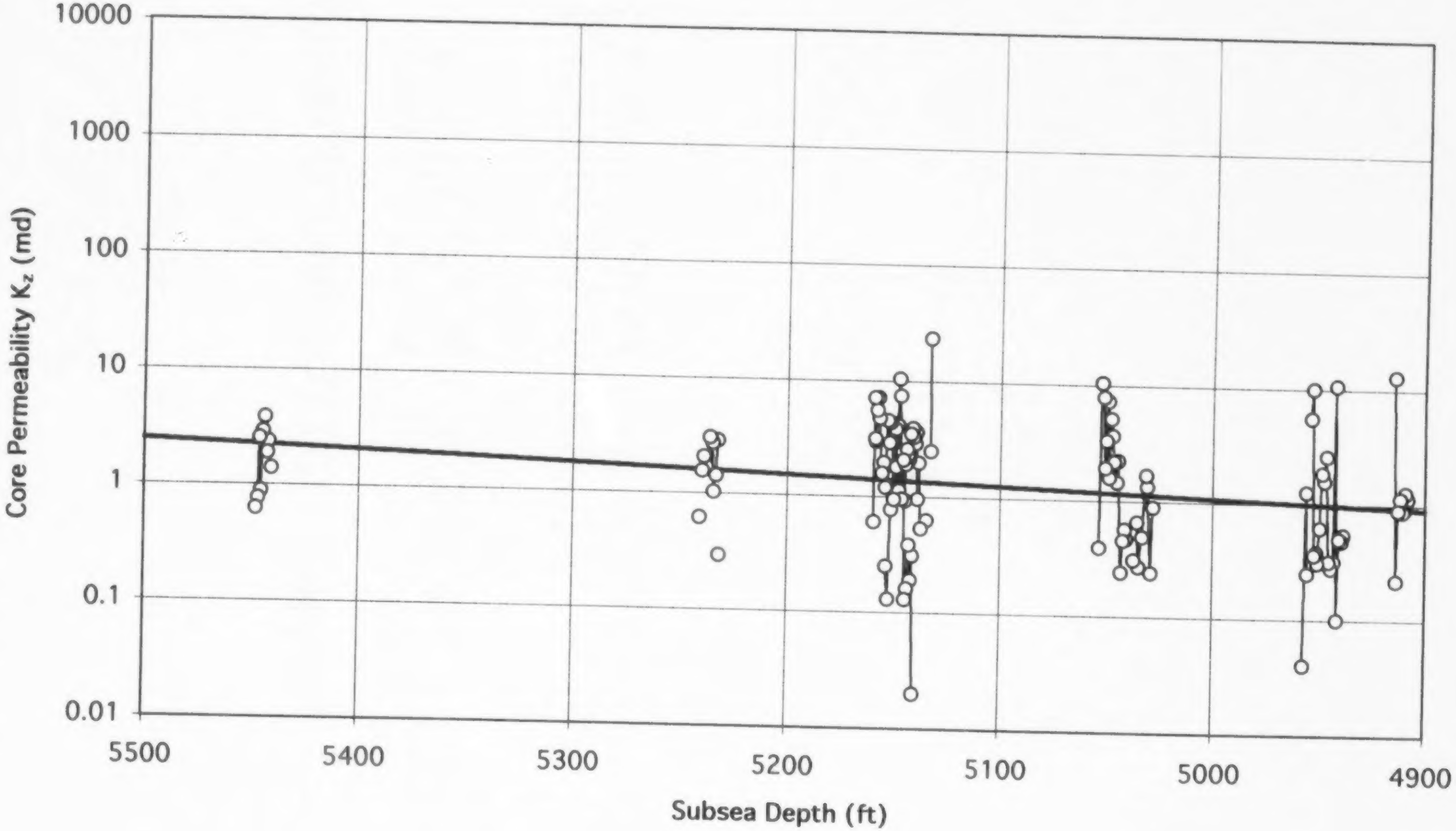

Figure 2.13(a): Core Vertical Permeability K_z vs Depth

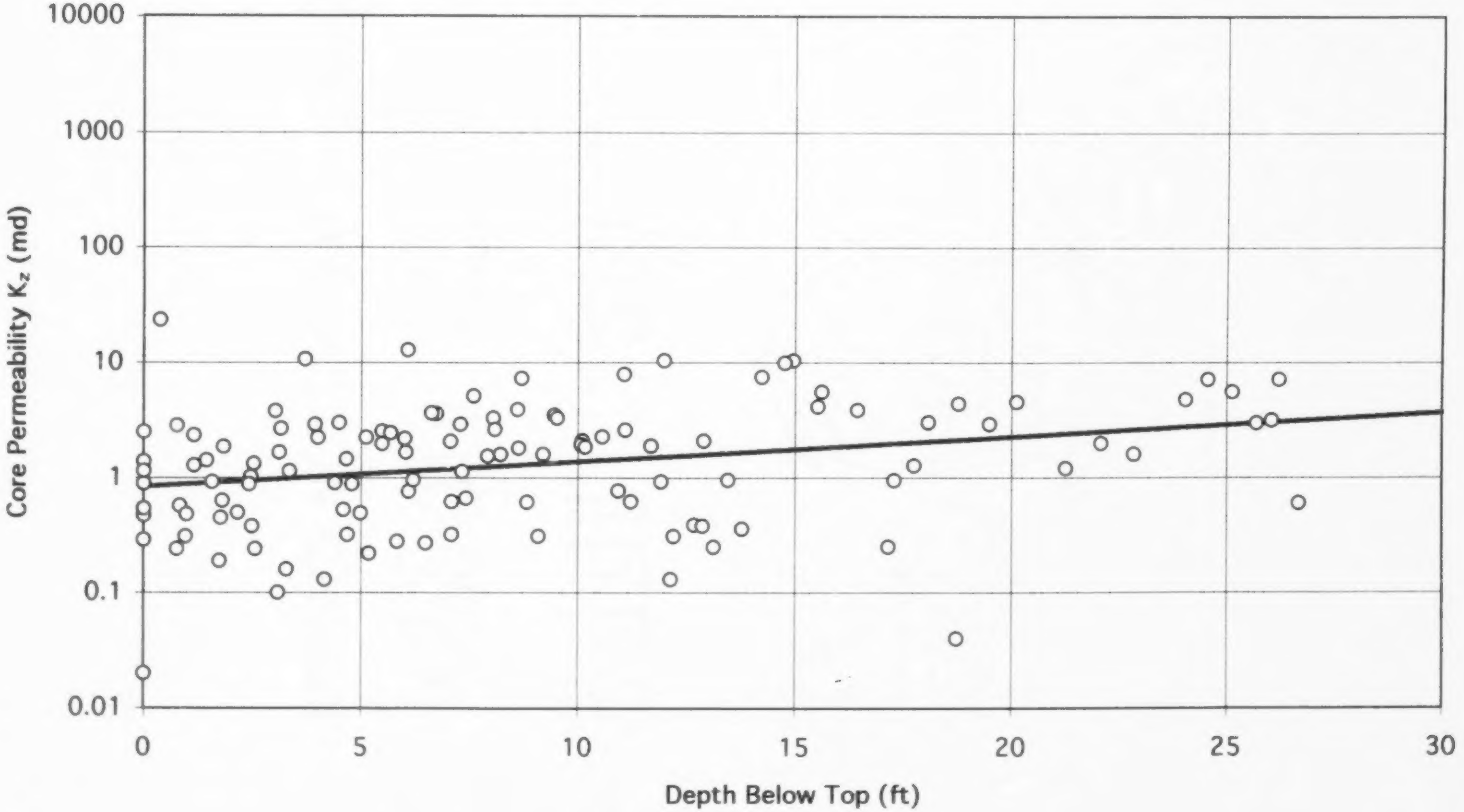

Figure 2.13(b): Core Vertical Permeability K_z Vertical Trend

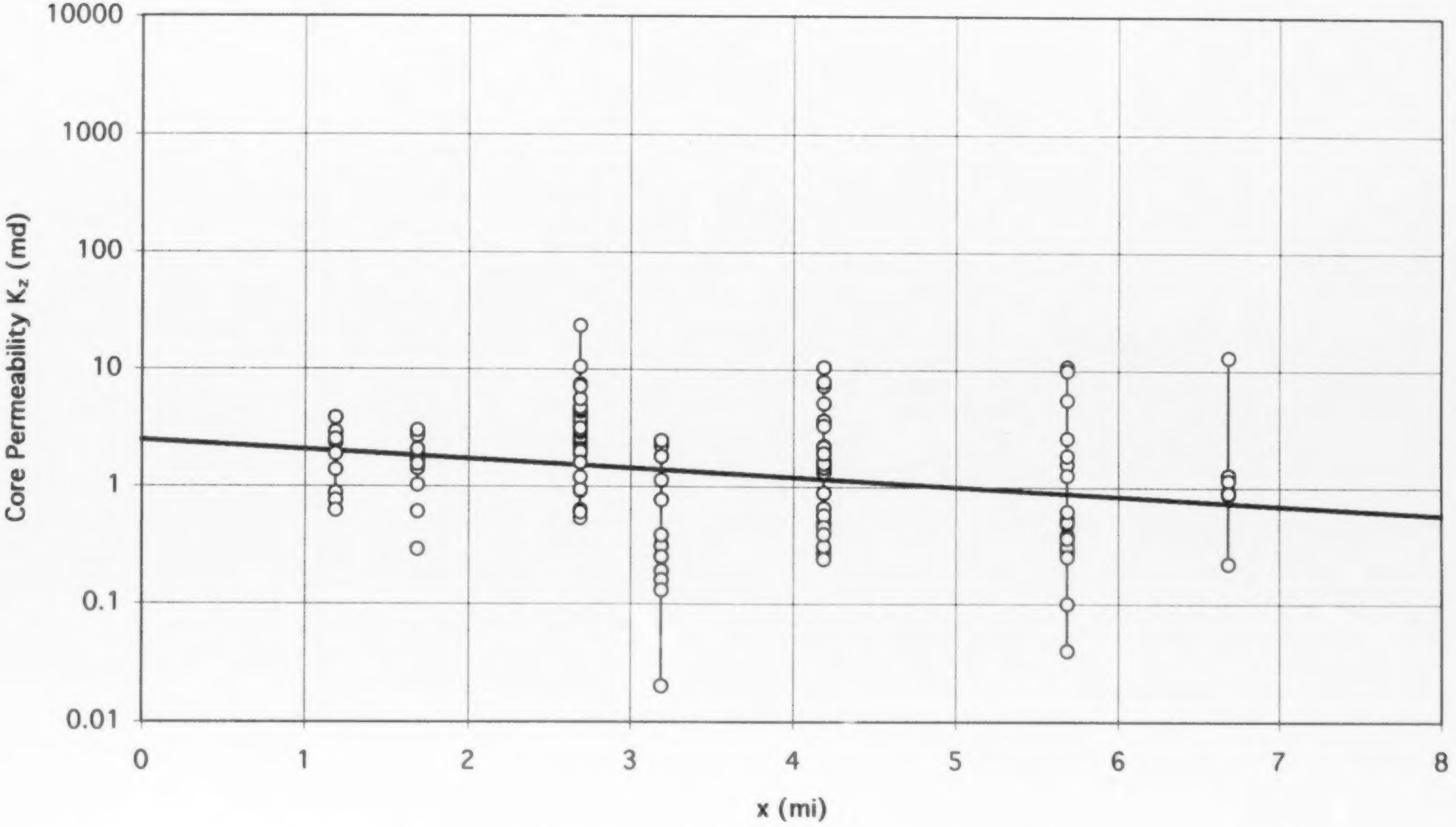

Figure 2.13(c): Core Vertical Permeability K_z East-West Trend

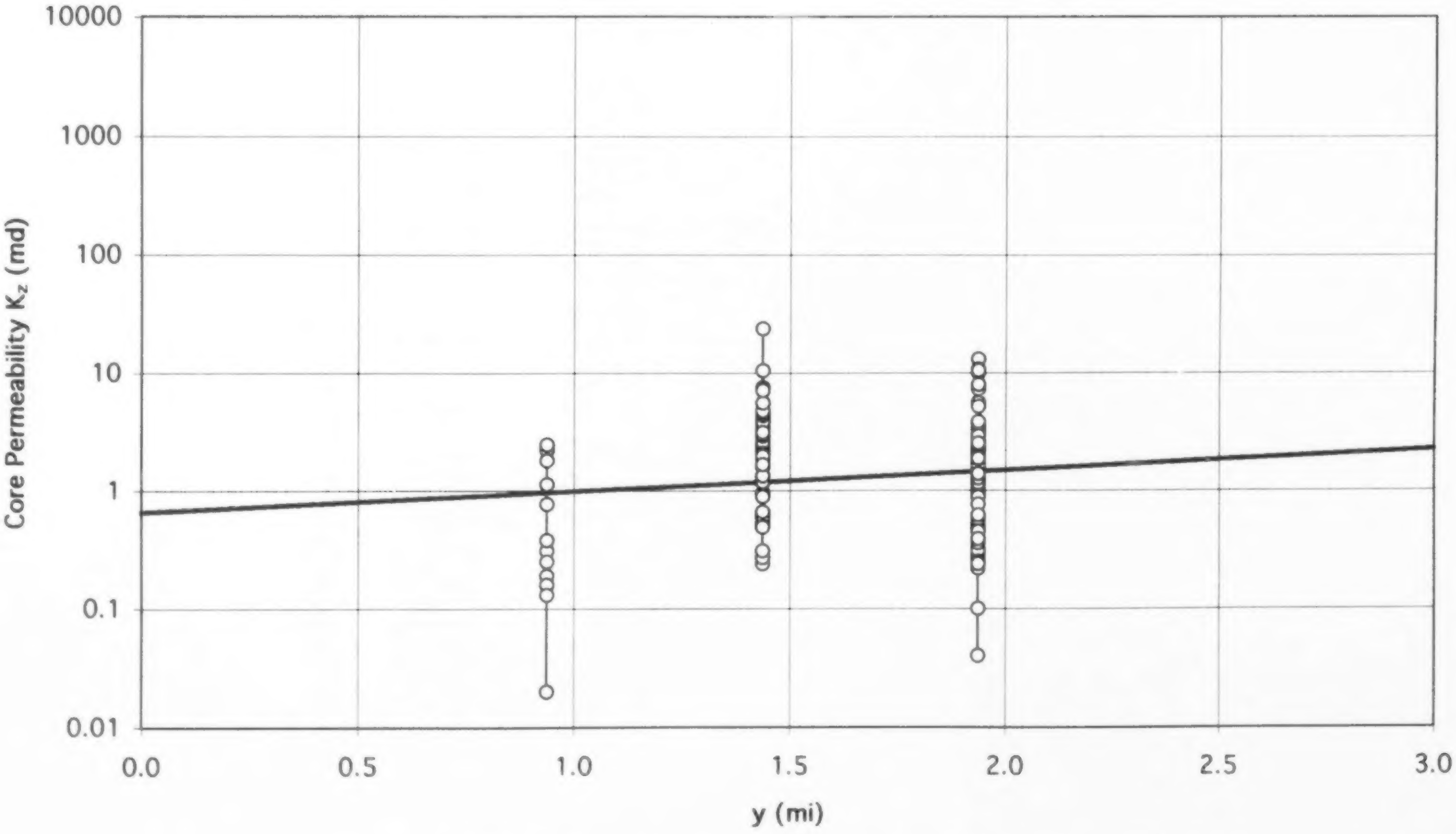

Figure 2.13(d): Core Vertical Permeability K_z North-South Trend

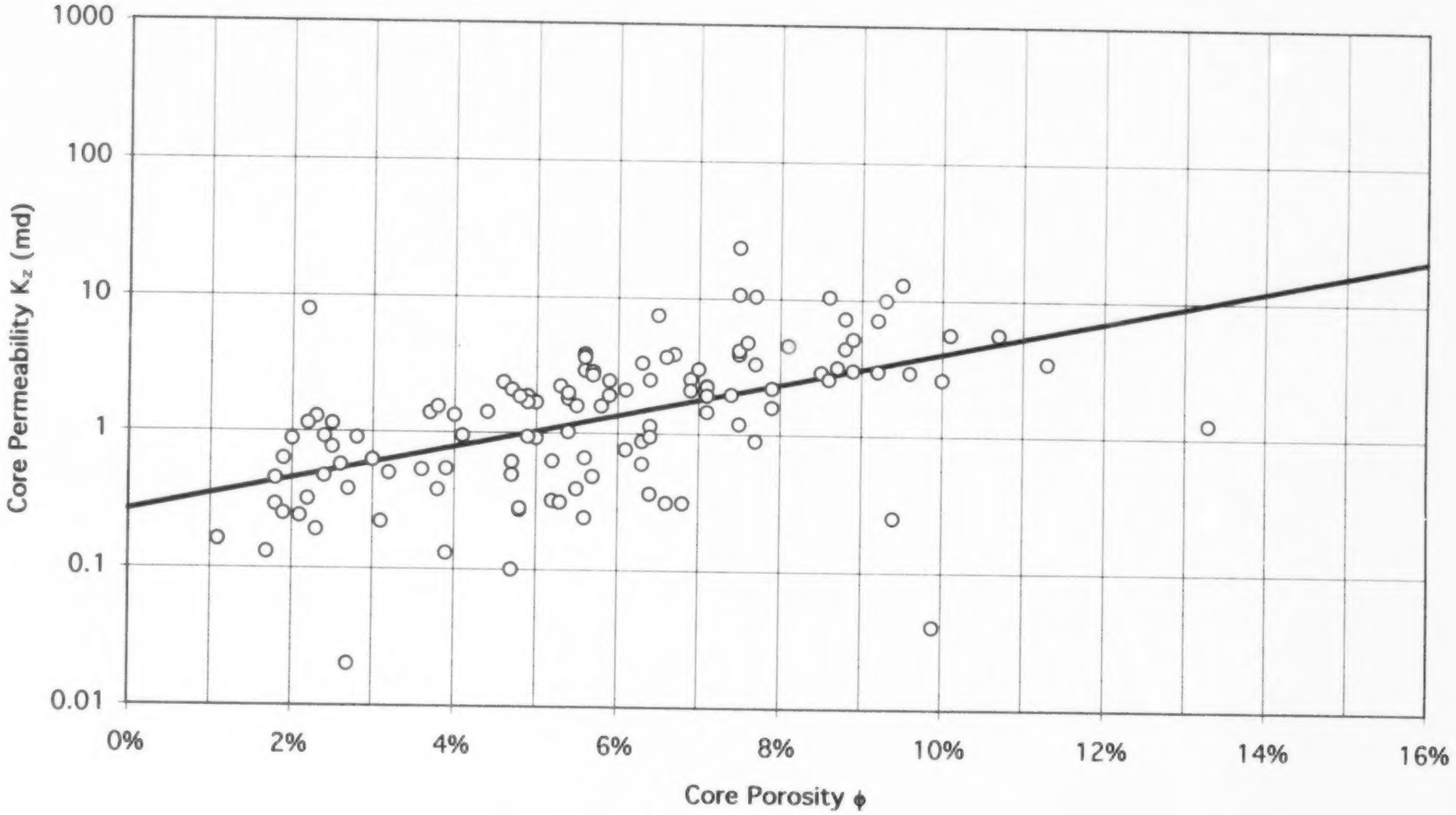

Figure 2.13(e): Core Vertical Permeability K_z vs Core Porosity ϕ

	Chedderville Viking A Core Summary					Zone Thickness	Δz-weighted Porosity	Log-mean Permeability	Log-mean Permeability	Log-mean Permeability	Rock Compressibility	Water Saturation	Bulk Water Fraction
Well	LSD	SEC	TWP	RGE	W	Δz (ft)	ϕ	Kx (md)	Ky (md)	Kz (md)	cr (1/psi)	Sw	$\phi\ S_w$
1	8	7	37	7	5	29.53	4.05%	1.94	1.31	0.23	7.14e-06	32.0%	0.0130
2	14	7	37	7	5	27.89	7.09%	5.85	3.94	2.64	5.64e-06	23.7%	0.0168
3	16	8	37	7	5	34.45	7.25%	1.59	1.51	0.58	5.59e-06	33.8%	0.0245
4	6	14	37	7	5	22.97	3.42%	15.07	12.09	1.17	7.70e-06	41.8%	0.0143
5	6	15	37	7	5	19.69	6.32%	7.27	5.58	0.69	5.92e-06	27.5%	0.0174
6	8	17	37	7	5	16.40	5.64%	6.77	3.85	1.76	6.20e-06	28.7%	0.0162
7	6	13	37	8	5	13.12	5.09%	6.64	9.23	1.41	6.47e-06		
8	8	14	37	8	5	18.04	5.40%	2.29	2.15	1.60	6.31e-06	29.5%	0.0159
					Zone	22.76	5.64%	4.94	3.77	1.27	6.37e-06	28.4%	0.0169

Permeability Averaging: Geometric Log Mean

Rock Compressibility Coefficient: Hall's porosity correlation (Ahmed, T., p236)

Water Saturation: Canadian Hunter Petrophysical Summary (Logs)

Bulk Water Averaging: Δz-weighted

Table 2.3: Core and Log Data Summary

2.7 High-Permeability Channel

The inclusion of the high-permeability channel in the reservoir model is paramount to history matching recorded bottomhole pressures and forecasting production accurately. The modelling of this channel is the critical link in the chain of reservoir characteristics. This is the vehicle by which pressure is maintained throughout the tight reservoir. Pressure communication within the channel media is prompt and local pressure gradients are equalized rapidly.

The initial reservoir model considered a two-dimensional (2-D) areal grid only, using average vertical reservoir properties. The high permeability zones were considered thin and insignificant. These were averaged in with the matrix. The result gave an unacceptable pressure history match, with predicted bottomhole pressures declining at phenomenally rapid rates. In the simulation, pressure fox holes grew rapidly in the tight porous media and historical production rates could not be sustained effectively. The drainage radii of producing wells was small. Fluid mobility was limited to these regions which collectively spanned a fraction of entire pool. The actual pressure decline history did not seem to be consistent with the 2-D reservoir model. Reasons were posed to be one of many:

- larger hydrocarbon deposit than assumed
- incorrect pressure initialization
- an unaccounted aquifer
- pressure communication with an adjacent pool
- pressure communication with other formations
- enhanced pressure communication within the pool

Most of the reasons were ruled out by the process of elimination through logic or simulation. The dimensions of the hydrocarbon deposit and the initial pressure had to be drastically manipulated in order to fit the pressure history. This was not acceptable and was therefore ruled out. The petrophysical data gave no evidence of an aquifer, and this too was ruled out. The only adjacent pool that could effect the reservoir pressure in the required manner was the Chedderville Viking "S" Caroline Pool (Figure 2.1). The fault separating Viking "A" from Caroline shifted the pools relative position by twisting and vertically translating the pools apart. The only communication between pools that could potentially take place was at an isolated seam on the south-western tip of Viking "A". This, however, could not account for the high pressure source needed for the history match, and was also ruled out. There was some evidence of pressure communication between the Viking "A" pool and a lower Mannville formation at a single well (14-09-37W5). This was deduced after an acceptable history match was attained and will be discussed at length later. Even though this presents certain complications in reservoir modelling, it does not account for pressure maintenance on the reservoir scale. The final reason considered was that a high permeability channel, no matter how thin, could have a significant effect on the overall reservoir pressure response. The three-dimensional (3-D) reservoir model, with an upper layer representing the channel, seemed to work.

The 3-D reservoir model incorporating the high permeability channel considered a 2-layer system with a thin upper layer (k=1) appended on the initial 2-D 54×18 rock matrix grid (k=2). Computational constraints eliminated higher dimensional configurations. The high permeability channel was assumed to span all contiguous wells that had supported its existence with core data as shown in Figure 2.14(a). Furthermore, it was assumed that the partial analysis on core sample for 08-14-37-8W5 had missed channel identification, and was also grouped within the continuous convex region defining the channel domain. History matching results supported this assumption. The actual channel appears to be isolated in the top 6 feet of the perforation zone, running from a constant 1 feet thickness in the lower third of the reservoir and increasing to a maximum of 2.5 feet in the upper third, as shown in Figure 2.14(b). The two-layer model explicitly lumps the channel directly on top of the perforation zone[4]. The rock matrix layer is also characterized to implicitly account for both channel thickness and permeability through geometric averaging. This simple model is intended to capture the gross channel functionality while preserving well productivity to a single layer. Fluids will readily flow in the channel maintaining pressure communication throughout. Actual well inflow will be highly inter-dependent between channel and matrix flows. The relative vertical position of the channel with respect to the rock matrix is essential for successful waterflood operations. Water prefers to flow below the oil and along the bottom of the perforation zone. If the channel appeared on the bottom of the perforation zone, the injected water would preferentially flow along the bottom and effectively bypass the bulk of the oil deposit above.

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[4] It should be noted that this is the simplest reservoir model that describes the 3-D system, and that more rigorous models would try to place the channel in its correct vertical position.

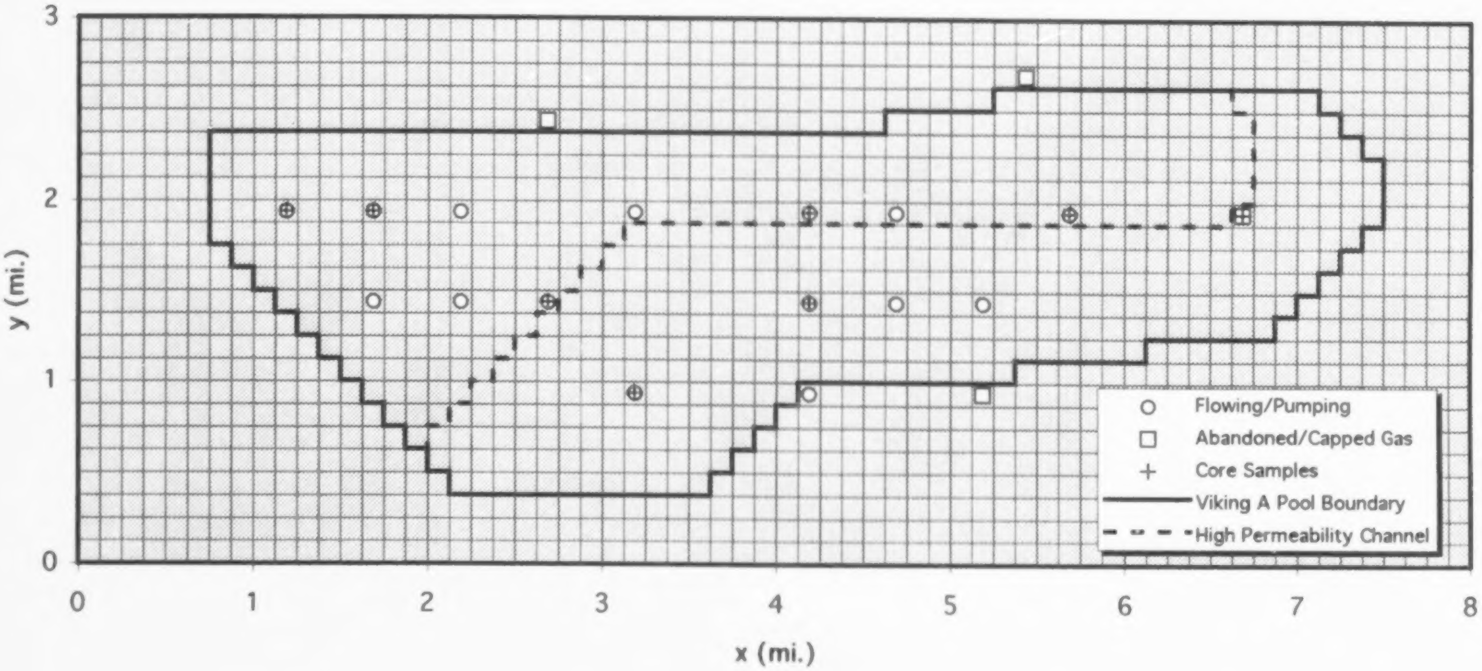

3
2
1
0
y (mi.)
0
1
2
3
4
5
6
7
8
x (mi.)
○ Flowing/Pumping
□ Abandoned/Capped Gas
+ Core Samples
Viking A Pool Boundary
High Permeability Channel

Figure 2.14 (a): High Permeability Channel

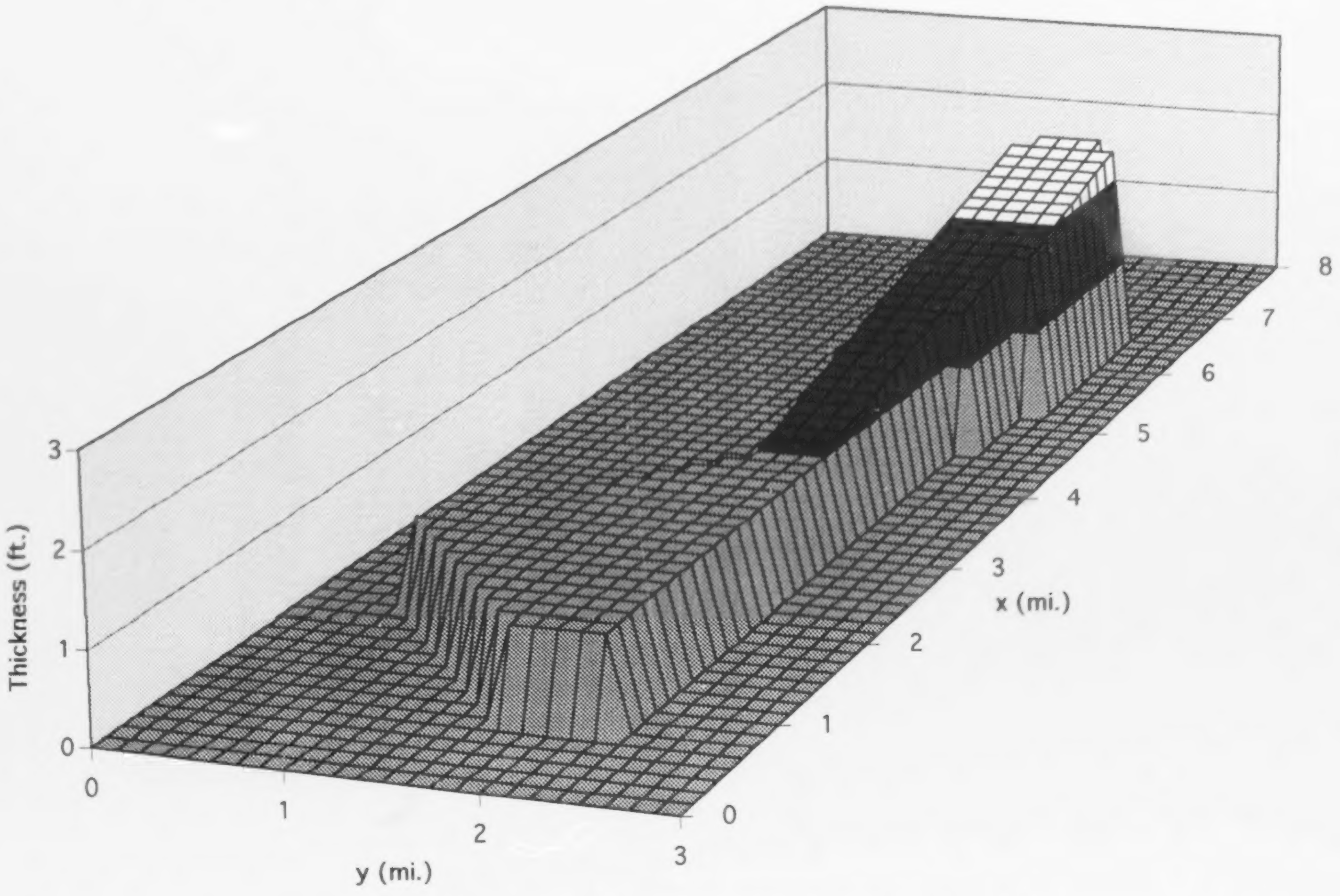


Figure 2.14(b): Channel Thickness Δz (k=1)

2.8 Three-Dimensional Reservoir Model

The 3-D reservoir geometry can be modelled by grid block volumes representing the channel (k=1) and matrix (k=2), as shown in Figures 2.15(a) and 2.15(b). The numeric values for layer thickness and layer depth are listed in Tables 2.4 and 2.5, respectively. Corresponding contour plot visualizations are presented in Figures 2.16(a) and 2.16(b).

Assigning values to the reservoir properties of porosity and absolute rock permeabilities was an iterative task governed by history matching. Channel layer (k=1) properties were assumed to be homogeneous. Log-mean values of K_x=1220 md and K_y=855 md were assigned to the horizontal channel permeability. The vertical channel permeability K_z =5 md and porosity ϕ=10% were estimated from core data. The bottom matrix layer (k=2) was segmented into two major rock types. A smooth transition was assumed to separate a homogeneous region situated below the high permeability channel from the other region some distance away. The procedure used the correlations established in Section 2.5 to inter-relate reservoir properties. Permeability K_x was designated as the control parameter. K_y and K_z were correlated to K_x using Eqn 2.2 and 2.4. Porosity ϕ was correlated to the vertical permeability K_z using Eqn 2.5. The initial water saturation S_w was assumed to be irreducible, and correlated to the porosity ϕ using Eqn 2.6. The history matched properties in the homogeneous zone below the channel were K_x=8.0 md, K_y=5.4 md, K_z=1.4 md, ϕ=6.2% and S_w=27.5%. The other region was determined to be K_x=2.0 md, K_y=1.7 md, K_z=0.9 md, ϕ=4.6% and S_w=37.3%. The transition region was determined patiently through trial and error. The resulting numeric assignment for K_x, K_y, K_z, ϕ and S_w distributions are tabulated in Tables 2.6(a)-(e). Corresponding contour plot visualizations are presented in Figures 2.17(a)-(e). These values are representative of their statistical distributions (Section 2.5).

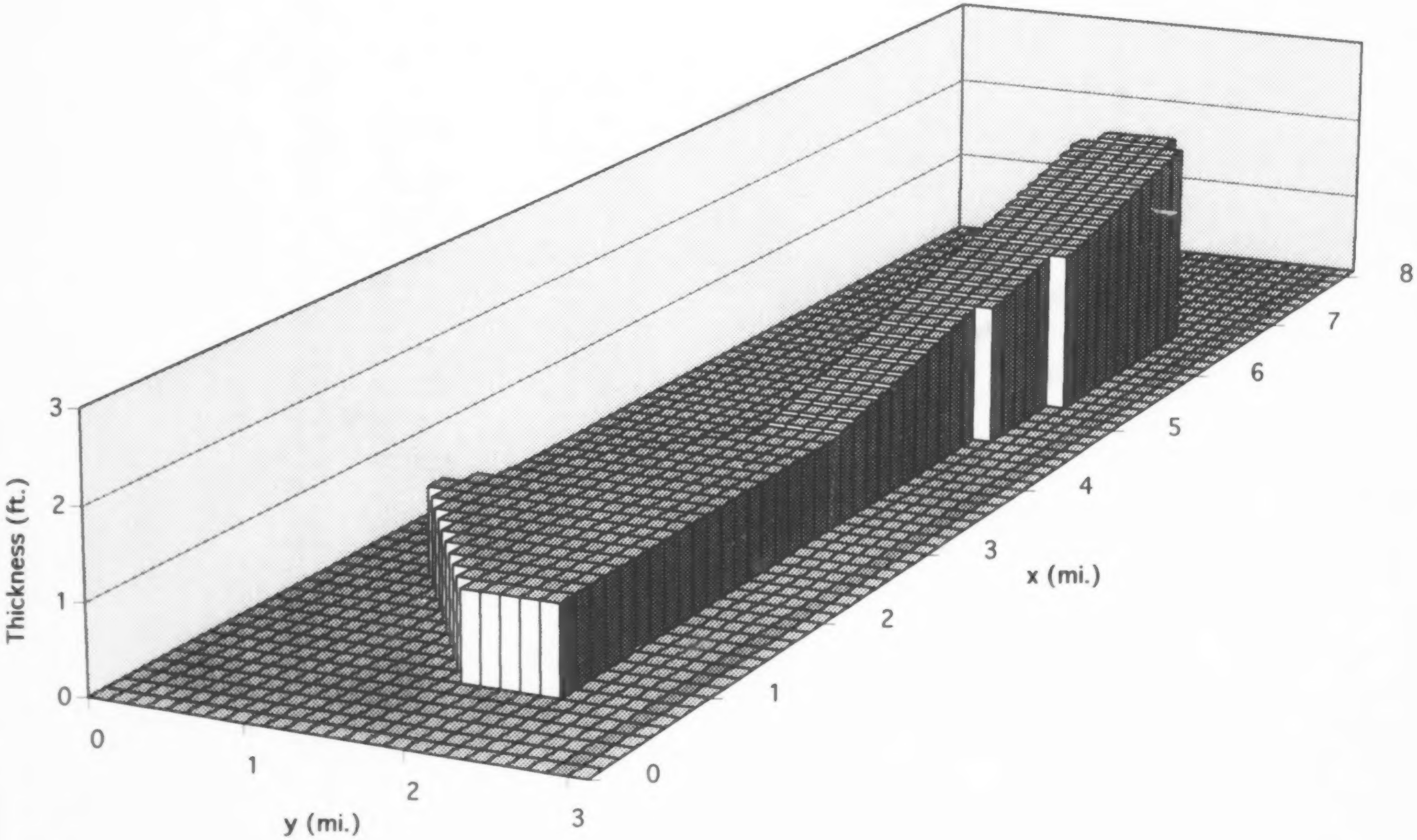


Figure 2.15(a): Channel Grid Block Thickness Δz (k=1)

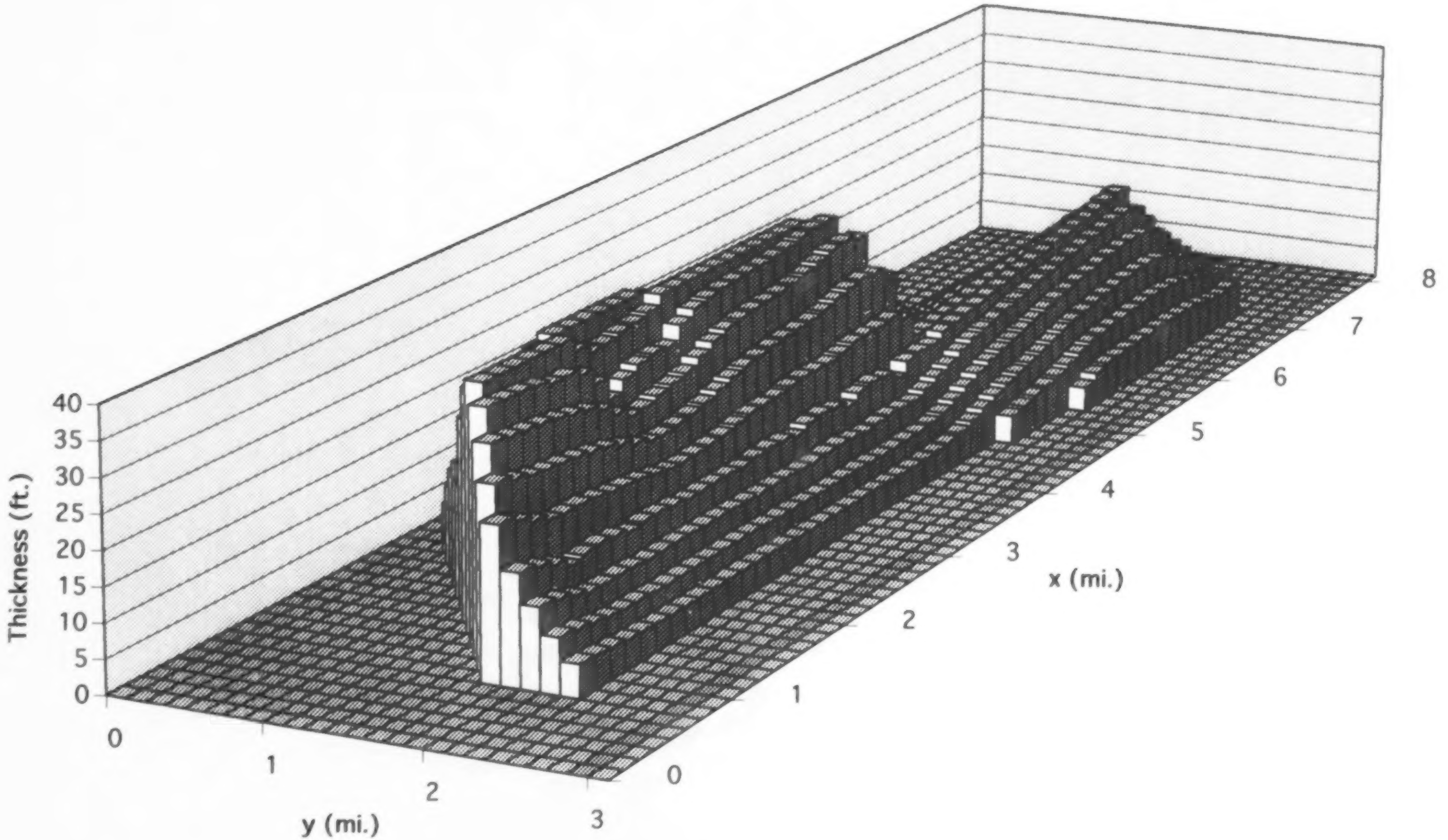


Figure 2.15(b): Matrix Grid Block Thickness Δz (k=2)

Nx	54
Ny	18
Nz	2

I	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
Δx (ft)	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660

J	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Δy (ft)	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660

k = 1	Δz (ft)																																																					
J	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
1																																																						
2																																																						
3										1.00																																												
4									1.00	1.00	1.00																																											
5								1.00	1.00	1.00	1.00	1.00																																										
6							1.00	1.00	1.00	1.00	1.00	1.00	1.00																																									
7						1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00																																								
8					1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00																																							
9				1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00																																						
10			1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00																																					
11		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00																																				
12	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00																																			
13	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.05	1.10	1.15	1.20	1.25	1.30	1.35	1.40	1.45	1.50	1.55	1.60	1.65	1.70	1.75	1.80	1.85	1.90	1.95	2.00	2.05	2.10	2.15	2.20	2.25	2.30	2.35							
14	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.05	1.10	1.15	1.20	1.25	1.30	1.35	1.40	1.45	1.50	1.55	1.60	1.65	1.70	1.75	1.80	1.85	1.90	1.95	2.00	2.05	2.10	2.15	2.20	2.25	2.30	2.35	2.40						
15	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.05	1.10	1.15	1.20	1.25	1.30	1.35	1.40	1.45	1.50	1.55	1.60	1.65	1.70	1.75	1.80	1.85	1.90	1.95	2.00	2.05	2.10	2.15	2.20	2.25	2.30	2.35	2.40						
16	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.05	1.10	1.15	1.20	1.25	1.30	1.35	1.40	1.45	1.50	1.55	1.60	1.65	1.70	1.75	1.80	1.85	1.90	1.95	2.00	2.05	2.10	2.15	2.20	2.25	2.30	2.35	2.40						
17																																1.60	1.65	1.70	1.75	1.80	1.85	1.90	1.95	2.00	2.05	2.10	2.15	2.20	2.25	2.30	2.35	2.40						
18																																					1.85	1.90	1.95	2.00	2.05	2.10	2.15	2.20	2.25	2.30	2.35							

k = 2	Δz (ft)																																																					
J	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
1												7.5	7.8	7.8	7.7	7.4	7.0	6.5	6.0	5.7	5.5	5.5	5.4																															
2											11.8	12.4	12.8	13.0	12.8	12.3	11.5	10.7	9.8	9.3	9.1	9.1	9.0	8.6																														
3										15.5	16.8	17.8	18.3	18.5	18.2	17.5	16.5	15.2	13.9	13.0	12.9	13.1	13.2	12.8	11.9																													
4									18.3	20.4	22.1	23.3	24.0	24.1	23.8	23.0	21.6	19.9	18.0	16.6	16.9	17.6	18.0	17.6	16.6	14.8																												
5								19.7	22.9	25.5	27.5	28.8	29.4	29.5	29.1	28.3	26.8	24.9	22.6	19.7	21.5	22.7	23.2	23.0	22.0	20.1	17.2																											
6							27.8	27.4	28.8	30.8	32.6	33.5	33.9	33.9	33.6	33.0	31.7	30.0	28.3	27.1	27.4	28.1	28.5	28.4	27.6	26.0	23.4	20.0	16.4	12.7	9.1	6.3	4.7	4.0	3.9	3.9	3.9																	
7						33.6	33.2	33.2	33.8	34.9	36.1	36.1	36.1	36.1	36.1	36.1	35.2	34.3	33.4	32.9	32.9	33.1	33.3	33.2	32.8	31.9	30.1	26.7	22.1	17.2	12.4	8.8	6.8	6.3	6.4	6.6	6.6	6.3	5.9	5.4	4.9	4.4	3.8											
8					36.1	36.1	36.1	36.1	36.1	36.1	34.0	32.7	32.9	33.5	33.8	34.4	36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1	32.4	27.3	21.2	14.9	10.1	8.5	8.6	9.2	9.7	9.7	9.3	8.9	8.4	7.9	7.5	7.0	6.5	6.2	5.9	5.5	4.9	4.0					
9				34.1	34.0	33.9	33.6	32.8	32.8	31.9	29.5	26.2	28.1	29.2	29.7	29.5	31.9	33.2	33.8	34.2	34.4	34.5	34.6	34.8	35.2	35.8	36.3	36.1	31.1	24.4	17.0	9.8	10.1	10.9	11.9	13.1	12.6	12.2	11.8	11.5	11.1	10.8	10.4	10.1	9.8	9.5	8.9	8.1	6.8	5.2				
10			30.6	30.2	29.9	29.7	29.3	28.7	28.2	27.1	25.4	24.0	24.2	25.0	25.5	26.2	27.5	28.7	29.5	30.0	30.3	30.5	30.8	31.1	31.6	32.4	33.2	33.5	32.8	26.4	19.4	14.3	12.9	13.3	14.2	14.9	15.0	14.8	14.6	14.4	14.1	14.0	13.8	13.6	13.5	13.2	12.7	11.6	10.0	8.0	5.8			
11		26.5	25.7	25.0	24.7	24.5	24.1	23.7	23.2	22.4	21.5	20.7	20.7	21.0	21.5	22.0	22.8	23.7	24.2	24.7	25.0	25.3	25.5	25.8	26.3	27.0	27.6	28.0	27.8	26.2	19.8	16.2	15.3	15.5	16.0	16.6	16.8	16.9	16.9	16.9	16.8	16.8	16.9	16.9	16.9	16.9	16.5	15.4	13.4	10.8	8.2	5.6		
12	22.4	21.5	20.3	19.2	19.0	19.0	18.8	18.4	18.2	17.9	17.4	17.0	16.9	17.1	17.3	17.6	18.1	18.6	18.8	18.9	19.3	19.7	19.6	19.6	20.1	20.7	20.9	20.8	21.1	20.0	16.4	16.4	16.6	16.9	17.3	17.8	18.1	18.4	18.6	18.8	18.9	19.1	19.4	19.6	19.8	20.0	20.1	19.3	16.7	13.5	10.4	7.5	5.0	
13	16.1	15.5	14.5	13.1	13.7	14.0	13.7	13.1	13.5	13.5	13.4	13.1	13.1	13.2	13.2	13.1	13.5	13.7	13.6	13.1	14.0	14.3	14.0	13.1	14.3	14.8	14.5	13.1	14.9	15.3	15.2	16.4	16.8	17.2	17.6	18.0	18.5	18.9	19.3	19.7	20.1	20.5	20.9	21.3	21.7	22.1	22.6	23.0	18.5	14.5	11.1	8.1	5.8	3.9
14	11.9	11.3	10.6	9.9	9.8	9.9	9.8	9.6	9.7	9.8	9.8	9.7	9.7	9.8	9.7	9.7	9.7	9.8	9.7	9.6	9.9	10.0	9.8	9.6	9.9	10.1	10.0	9.9	10.7	11.7	12.6	13.7	14.5	15.1	15.7	16.2	16.7	17.2	17.7	18.2	18.6	19.1	19.5	19.9	20.4	20.7	20.9	20.1	17.4	14.2	11.2	8.8	6.5	4.9
15	8.1	7.8	7.3	6.9	6.7	6.7	6.6	6.5	6.6	6.7	6.7	6.7	6.7	6.7	6.6	6.6	6.5	6.5	6.5	6.5	6.6	6.6	6.6	6.5	6.5	6.6	6.7	6.9	7.5	8.4	9.5	10.5	11.4	12.1	12.7	13.3	13.9	14.5	15.1	15.6	16.0	16.4	16.8	17.2	17.6	17.8	17.6	16.7	14.9	12.7	10.5	8.5	7.0	5.7
16	4.8	4.7	4.4	4.2	4.0	4.0	3.9	3.9	3.9	4.0	4.0	4.0	4.0	4.0	4.0	3.9	3.9	3.8	3.8	3.9	3.9	3.9	3.9	3.8	3.8	3.9	4.0	4.2	4.7	5.4	6.3	7.3	8.1	8.7	9.3	10.0	10.6	11.3	11.9	12.4	12.8	13.1	13.5	13.8	14.0	14.1	13.8	13.1	11.9	10.5	9.1	8.0	7.1	
17																																4.3	4.9	5.4	5.9	6.4	7.2	8.0	8.7	9.0	9.3	9.5	9.8	10.0	10.1	10.1	9.9	9.4	8.7	8.0	7.4	7.2		
18																																					3.8	5.1	5.6	5.7	5.8	5.9	6.1	6.2	6.3	6.3	6.1	5.9	5.5	5.8	5.5			

Table 2.4: Reservoir Grid Dimensions

k = 1	Depth (ft)																																																					
N	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
1																																																						
2																																																						
3										5196																																												
4									5207	5198	5188																																											
5								5220	5210	5199	5188	5176																																										
6							5232	5225	5214	5201	5187	5174	5162																																									
7						5242	5238	5231	5218	5202	5185	5170	5158	5148																																								
8					5248	5247	5245	5238	5222	5202	5182	5164	5152	5143	5135																																							
9				5249	5249	5248	5248	5247	5224	5201	5179	5157	5148	5140	5131	5122																																						
10			5248	5249	5248	5246	5243	5235	5218	5198	5177	5159	5147	5138	5130	5121	5114																																					
11		5246	5248	5248	5245	5241	5235	5225	5211	5193	5176	5160	5148	5139	5130	5121	5113	5104																																				
12	5243	5245	5246	5246	5242	5236	5227	5216	5203	5189	5174	5160	5149	5140	5131	5123	5113	5104	5093																																			
13	5240	5242	5243	5244	5237	5230	5220	5208	5197	5185	5172	5159	5150	5142	5134	5125	5115	5104	5093	5080	5074	5068	5061	5053	5045	5038	5030	5023	[illegible]	4974	4950	4926	4927	4927	4926	4924	4925	4925	4924	4923	4918	4913	4908	4904	4899	4894	4890							
14	5236	5237	5238	5236	5231	5224	5214	5204	5194	5183	5171	5161	5152	5145	5137	5128	5118	5107	5095	5083	5075	5067	5059	5051	5043	5034	5025	5013	4994	4971	4950	4933	4926	4923	4921	4920	4919	4919	4917	4913	4912	4907	4902	4897	4893	4888	4883	4877						
15	5232	5232	5232	5229	5224	5218	5210	5201	5191	5182	5172	5163	5155	5148	5141	5133	5122	5110	5098	5086	5076	5067	5058	5049	5040	5030	5019	5006	4989	4970	4952	4937	4928	4923	4920	4917	4915	4914	4912	[illegible]	4905	4901	4896	4891	4886	4881	4875	4869						
16	5226	5226	5225	5223	5218	5212	5205	5197	5189	5180	5172	5164	5157	5151	5145	5138	5126	5113	5100	5088	5077	5067	5057	5047	5037	5026	5015	5001	4986	4969	4954	4941	4931	4924	4919	4916	4913	4910	4907	4904	4900	4895	4891	4885	4880	4874	4868	4862						
17																																4943	4934	4926	4920	4915	4911	4907	4903	4899	4895	4890	4885	4880	4874	4868	4862	4855						
18																																					4910	4905	4900	4896	4891	4886	4881	4875	4869	4863	4856							

k = 2	Depth (ft)																																																					
N	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
1												5177	5170	5163	5156	5150	5143	5137	5132	5126	5120	5114	5108																															
2											5185	5177	5170	5162	5155	5148	5142	5136	5130	5124	5118	5112	5106	5100																														
3										5195	5186	5177	5169	5161	5153	5146	5140	5134	5128	5122	5116	5110	5104	5098	5092																													
4									5206	5197	5187	5177	5167	5159	5151	5143	5137	5131	5125	5120	5113	5107	5100	5094	5088	5083																												
5								5219	5209	5198	5187	5175	5165	5156	5147	5140	5133	5127	5122	5117	5109	5102	5096	5089	5083	5078	5073																											
6							5231	5224	5213	5200	5186	5173	5161	5152	5143	5136	5129	5123	5117	5111	5104	5097	5090	5083	5077	5070	5064	5056	5046	5034	5024	5015	5007	5000	4993	4987	4981																	
7						5241	5237	5230	5217	5201	5184	5169	5157	5147	5138	5131	5124	5119	5112	5106	5099	5092	5084	5077	5069	5061	5052	5042	5033	5023	5014	5005	4998	4992	4987	4981	4976	4969	4963	4957	4951	4945	4939											
8					5247	5246	5244	5237	5221	5201	5181	5163	5151	5142	5134	5126	5119	5113	5107	5100	5093	5086	5079	5071	5062	5052	5040	5029	5020	5011	5002	4995	4988	4983	4979	4976	4970	4963	4957	4951	4945	4940	4934	4929	4923	4918	4912	4907	4902					
9				5248	5248	5247	5247	5246	5223	5200	5178	5156	5147	5139	5130	5121	5115	5109	5102	5095	5088	5081	5073	5065	5055	5045	5032	5016	5009	5000	4991	4983	4977	4973	4971	4970	4963	4956	4951	4945	[illegible]	4934	4929	4923	4918	4913	4907	4902	4896	4891				
10			5247	5248	5247	5245	5242	5234	5217	5197	5176	5158	5146	5137	5129	5120	5113	5106	5098	5091	5083	5076	5068	5060	5051	5040	5028	5015	5003	4991	4980	4970	4964	4960	4958	4957	4953	4948	4943	4939	4934	4929	4923	4918	4913	4908	4903	4897	4891	4885	4879			
11		5245	5247	5247	5244	5240	5234	5224	5210	5192	5175	5159	5147	5138	5129	5120	5112	5103	5095	5087	5079	5072	5065	5057	5048	5038	5027	5015	5000	4984	4968	4956	4950	4947	4945	4944	4942	4939	4936	4932	4928	4923	4918	4913	4908	4903	4898	4892	4886	4880	4873	4867		
12	5242	5244	5245	5245	5241	5235	5226	5215	5202	5188	5173	5159	5148	5139	5130	5122	5112	5103	5092	5083	5075	5069	5062	5054	5046	5038	5029	5017	4998	4977	4957	4941	4935	4934	4933	4932	4932	4931	4929	4926	4922	4917	4912	4907	4902	4898	4893	4888	4881	4874	4867	4861	4855	
13	[illegible]	5241	5242	5243	5236	5229	5219	5207	5196	5184	5171	5157	5149	5141	5133	5124	5114	5103	5092	5079	5073	5066	5059	5052	5044	5036	5029	5021	4997	4973	4949	4925	4925	4925	4924	4923	4923	4923	[illegible]	4921	4916	4911	4906	4901	4897	4892	4887	4883	4875	4867	4860	4854	4848	4842
14	5235	5236	5237	5235	5230	5223	5213	5203	5193	5182	5170	5160	5151	5144	5136	5127	5117	5106	5094	5082	5073	5066	5058	5050	5042	5033	5024	5011	4992	4970	4948	4931	4924	4921	4920	4918	4917	4917	4916	4913	4910	4905	4900	4895	4890	4885	4880	4875	4868	4860	4853	4846	4840	4835
15	5231	5231	5231	5228	5223	5217	5209	5200	5190	5181	5171	5162	5154	5147	5140	5132	5121	5109	5097	5085	5075	5066	5057	5048	5039	5029	5018	5004	4987	4969	4950	4936	4927	[illegible]	4918	4915	4914	4912	4910	4907	4903	4899	4894	[illegible]	4884	4879	4873	4867	4860	4853	4845	4838	4832	4827
16	5225	5225	5224	5222	5217	5211	5204	5196	5188	5179	5171	5163	5156	5150	5144	5137	5125	5112	5099	5087	5076	5066	5056	5046	5036	5025	5013	5000	4984	4968	4952	4939	[illegible]	4923	4916	4914	4911	[illegible]	4905	4902	4898	4893	4888	4883	4878	4872	4866	4860	4853	4845	4838	4831	4824	
17																																[illegible]	4932	4924	4918	4913	4909	[illegible]	[illegible]	[illegible]	4893	4888	4883	4878	4872	4866	4860	4853	4846	4838	4831	4823		
18																																					4908	4905	[illegible]	4894	4889	4884	4879	4873	4867	4860	4854	4847	4839	4832	4824			

Table 2.5: Reservoir Grid Depth

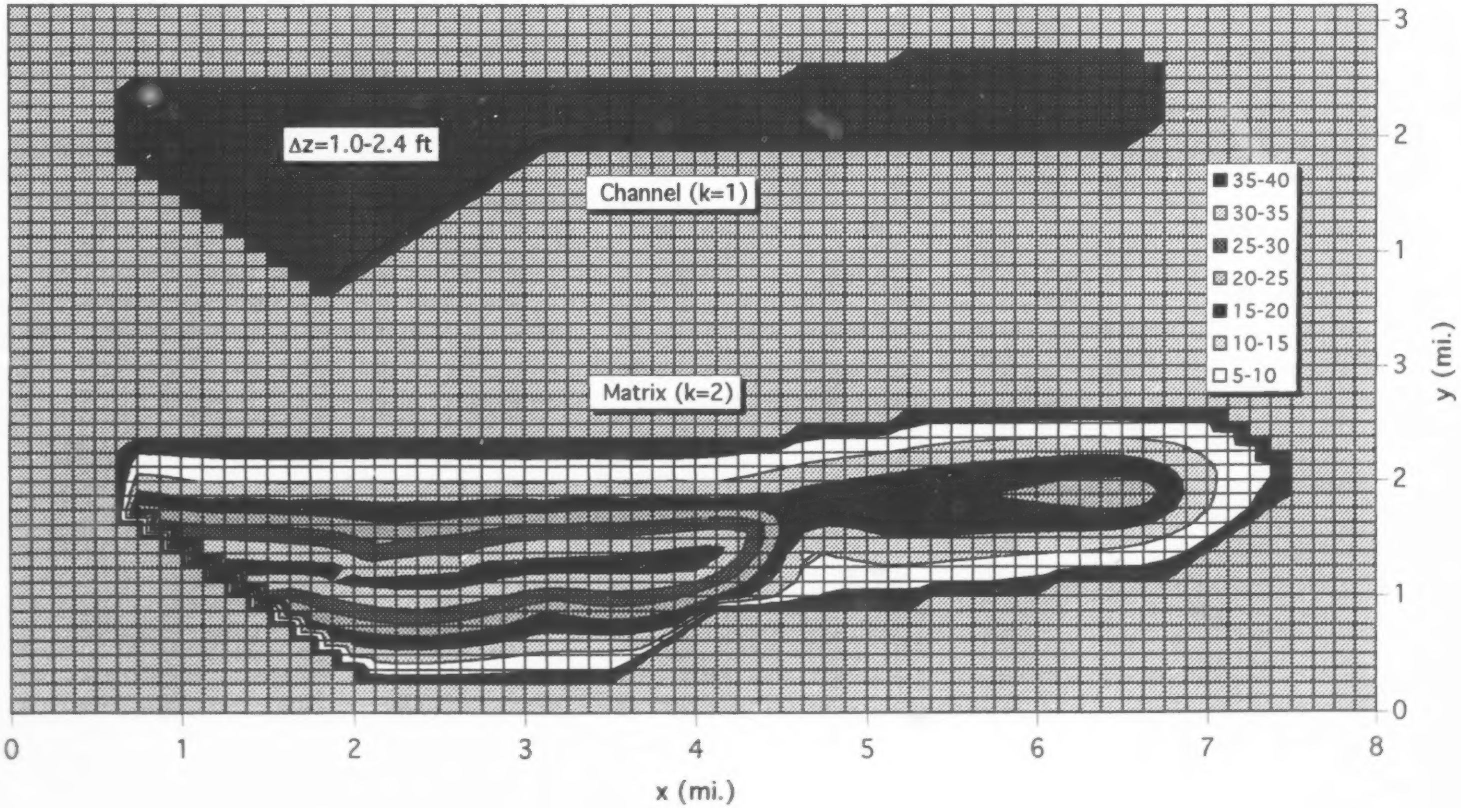
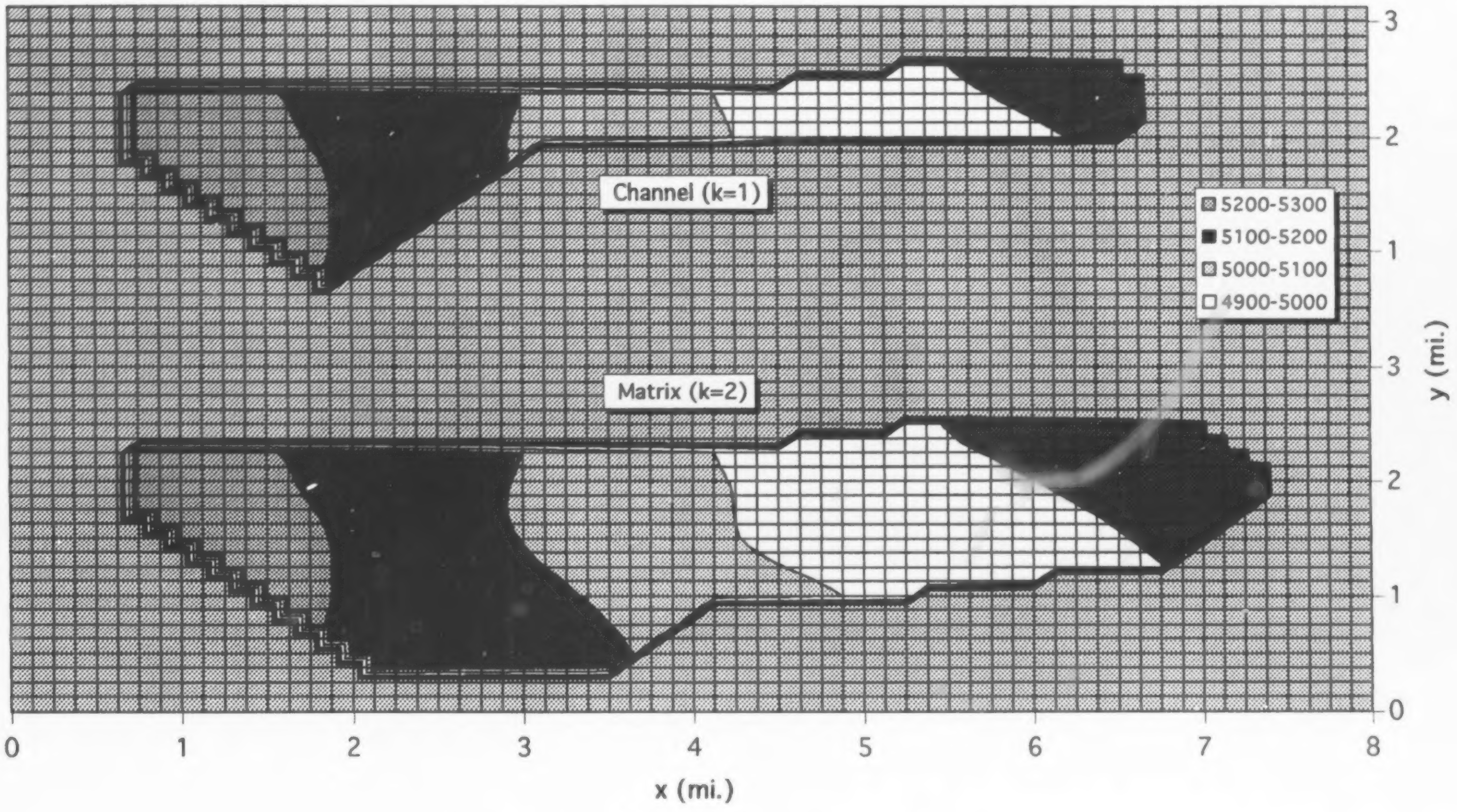


Figure 2.16(a): Reservoir Thickness Δz (ft)



Channel (k=1)
Matrix (k=2)
▨ 5200-5300
■ 5100-5200
▨ 5000-5100
☐ 4900-5000
0
1
2
3
4
5
6
7
8
x (mi.)
0
1
2
3
1
2
3
y (mi.)

Figure 2.16(b): Reservoir Subsea Depth (ft)

k = 1	Kx-Permeability (m darcy)																																																				
N	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
1																																																						
2																																																						
3										1220																																												
4									1220	1220	1220																																											
5								1220	1220	1220	1220	1220																																										
6							1220	1220	1220	1220	1220	1220	1220																																									
7						1220	1220	1220	1220	1220	1220	1220	1220	1220																																								
8					1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220																																							
9				1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220																																						
10			1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220																																					
11		1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220																																				
12	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220																																			
13	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220							
14	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220						
15	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220						
16	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220						
17																																1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220						
18																																					1220	1220	1220	1220	1220	1220	1220	1220	1220	1220	1220							

k = 2	Kx-Permeability (m darcy)																																																				
N	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
1												7.5	7.4	7.3	7.1	7.0	6.8	6.6	6.3	6.0	5.7	5.3	5.0																															
2											7.8	7.6	7.5	7.4	7.3	7.1	7.0	6.8	6.5	6.2	5.8	5.4	5.0	4.7																														
3										8.0	7.9	7.8	7.6	7.5	7.4	7.3	7.2	7.0	6.7	6.4	5.9	5.4	5.0	4.7	4.5																													
4									8.0	8.0	8.0	7.9	7.8	7.6	7.5	7.4	7.3	7.2	7.0	6.7	6.2	5.6	5.0	4.8	4.6	4.3																												
5								8.0	8.0	8.0	8.0	8.0	7.9	7.8	7.6	7.5	7.4	7.3	7.2	7.0	6.6	6.0	5.4	5.0	4.7	4.5	4.2																											
6							8.0	8.0	8.0	8.0	8.0	8.0	8.0	7.9	7.8	7.6	7.5	7.4	7.3	7.2	7.0	6.5	5.9	5.4	5.0	4.7	4.5	4.3	4.0	3.4	2.8	2.3	2.0	2.0	2.0	2.0	2.0																	
7						8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	7.9	7.8	7.6	7.5	7.4	7.4	7.2	7.0	6.5	5.9	5.4	5.0	4.7	4.5	4.3	4.0	3.4	2.8	2.3	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0											
8					8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	7.9	7.8	7.6	7.5	7.4	7.4	7.2	7.0	6.5	5.9	5.4	5.0	4.7	4.5	4.3	4.0	3.3	2.8	2.3	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0					
9				8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	7.9	7.8	7.6	7.5	7.5	7.4	7.2	7.0	6.5	5.9	5.4	5.0	4.7	4.5	4.2	4.0	3.4	3.0	2.6	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0				
10			8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	7.9	7.8	7.7	7.6	7.5	7.4	7.3	7.0	6.5	5.9	5.5	5.0	4.7	4.5	4.3	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	2.0	2.0	2.0	2.0			
11		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	7.9	7.8	7.8	7.7	7.6	7.5	7.3	7.0	6.5	6.1	5.7	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	4.0	2.0	2.0	2.0	2.0		
12	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	7.9	7.9	7.8	7.8	7.7	7.5	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	5.0	4.0	2.0	2.0	2.0	2.0	
13	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	7.0	5.0	4.0	2.0	2.0	2.0	2.0
14	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	6.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	7.0	5.0	4.0	2.0	2.0	2.0
15	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	7.0	5.0	4.0	2.0	2.0	2.0
16	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	7.0	5.0	4.0	2.0	2.0	
17																																8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	7.0	5.0	4.0	2.0		
18																																					8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	7.0	5.0	4.0	2.0			

Table 2.6(a): Horizontal Permeability K_x

k = 1	Ky-Permeability (m darcy)																																																				
J\I	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
1																																																						
2																																																						
3										855																																												
4									855	855	855																																											
5								855	855	855	855	855																																										
6							855	855	855	855	855	855	855																																									
7						855	855	855	855	855	855	855	855	855																																								
8					855	855	855	855	855	855	855	855	855	855	855																																							
9				855	855	855	855	855	855	855	855	855	855	855	855	855																																						
10			855	855	855	855	855	855	855	855	855	855	855	855	855	855	855																																					
11		855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855																																				
12	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855																																			
13	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855							
14	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855						
15	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855						
16	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855						
17																																855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855						
18																																					855	855	855	855	855	855	855	855	855	855	855							

k = 2	Ky-Permeability (m darcy)																																																				
J\I	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
1												5.1	5.0	5.0	4.9	4.8	4.7	4.6	4.4	4.2	4.0	3.8	3.6																															
2											5.3	5.2	5.1	5.0	5.0	4.9	4.8	4.7	4.5	4.3	4.1	3.8	3.6	3.5																														
3										5.4	5.3	5.3	5.2	5.1	5.0	5.0	4.9	4.8	4.6	4.4	4.2	3.9	3.6	3.4	3.3																													
4									5.4	5.4	5.4	5.3	5.3	5.2	5.1	5.0	5.0	4.9	4.8	4.6	4.3	4.0	3.6	3.5	3.3	3.2																												
5								5.4	5.4	5.4	5.4	5.4	5.3	5.3	5.2	5.1	5.0	5.0	4.9	4.8	4.5	4.2	3.9	3.6	3.4	3.3	3.1																											
6							5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.3	5.3	5.2	5.1	5.0	5.0	4.9	4.8	4.5	4.2	3.9	3.6	3.4	3.3	3.2	3.0	2.6	2.2	1.9	1.7	1.7	1.7	1.7	1.7																	
7						5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.3	5.3	5.2	5.1	5.1	5.0	4.9	4.8	4.5	4.2	3.9	3.6	3.4	3.3	3.2	3.0	2.6	2.2	1.9	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7											
8					5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.3	5.3	5.2	5.1	5.1	5.0	4.9	4.8	4.5	4.2	3.9	3.6	3.5	3.3	3.2	3.0	2.6	2.2	1.9	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7					
9				5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.3	5.3	5.2	5.1	5.1	5.0	4.9	4.8	4.5	4.2	3.9	3.6	3.4	3.3	3.1	3.0	2.6	2.3	2.1	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7				
10			5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.3	5.3	5.2	5.2	5.1	5.1	5.0	4.8	4.5	4.2	3.9	3.6	3.4	3.3	3.2	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	1.7	1.7	1.7	1.7			
11		5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.3	5.3	5.2	5.2	5.2	5.1	5.0	4.8	4.5	4.3	4.0	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.0	1.7	1.7	1.7	1.7		
12	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.3	5.3	5.3	5.3	5.2	5.1	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	3.6	3.0	1.7	1.7	1.7	1.7	
13	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	4.8	3.6	3.0	1.7	1.7	1.7	1.7
14	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	4.8	3.6	3.0	1.7	1.7	1.7
15	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	4.8	3.6	3.0	1.7	1.7	1.7
16	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	4.8	3.6	3.0	1.7	1.7	
17																																5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	4.8	3.6	3.0	1.7		
18																																					5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	4.8	3.6	3.0	1.7			

Table 2.6(b): Horizontal Permeability K_y

k = 1	Kz-Permeability (m darcy)																																																				
N	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
1																																																					
2																																																					
3										5																																												
4									5	5	5																																											
5								5	5	5	5	5																																										
6							5	5	5	5	5	5	5																																									
7						5	5	5	5	5	5	5	5	5																																								
8					5	5	5	5	5	5	5	5	5	5	5																																							
9				5	5	5	5	5	5	5	5	5	5	5	5	5																																						
10			5	5	5	5	5	5	5	5	5	5	5	5	5	5	5																																					
11		5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5																																				
12	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5																																			
13	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5							
14	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5						
15	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5						
16	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5						
17																																5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5						
18																																					5	5	5	5	5	5	5	5	5	5	5							

k = 2	Kz-Permeability (m darcy)																																																				
N	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
1												1.4	1.4	1.4	1.4	1.4	1.3	1.3	1.3	1.3	1.3	1.2	1.2																															
2											1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.3	1.3	1.3	1.2	1.2	1.2																														
3										1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.3	1.3	1.2	1.2	1.2	1.2																													
4									1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.3	1.3	1.2	1.2	1.2	1.2																												
5								1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.3	1.2	1.2	1.2	1.2	1.1																											
6							1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.3	1.2	1.2	1.2	1.2	1.2	1.1	1.1	1.0	0.9	0.9	0.9	0.9	0.9	0.9																	
7						1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.3	1.2	1.2	1.2	1.2	1.2	1.1	1.1	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9											
8					1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.3	1.2	1.2	1.2	1.2	1.2	1.1	1.1	1.0	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9					
9				1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.3	1.2	1.2	1.2	1.2	1.2	1.1	1.1	1.0	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9				
10			1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.3	1.2	1.2	1.2	1.2	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	0.9	0.9	0.9	0.9			
11		1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.3	1.3	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.1	0.9	0.9	0.9	0.9		
12	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.2	1.1	0.9	0.9	0.9	0.9	
13	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.2	1.1	0.9	0.9	0.9	0.9
14	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.2	1.1	0.9	0.9	0.9
15	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.2	1.1	0.9	0.9	0.9
16	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.2	1.1	0.9	0.9	
17																																1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.2	1.1	0.9		
18																																					1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.2	1.1	0.9			

Table 2.6(c): Vertical Permeability K_z

k = 1	ϕ Porosity																																																					
N	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
1																																																						
2																																																						
3										0.1																																												
4									0.1	0.1	0.1																																											
5								0.1	0.1	0.1	0.1	0.1																																										
6							0.1	0.1	0.1	0.1	0.1	0.1	0.1																																									
7						0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1																																								
8					0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1																																							
9				0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1																																						
10			0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1																																					
11		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1																																				
12	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1																																			
13	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1							
14	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1						
15	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1						
16	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1						
17																																0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1						
18																																					0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1							

k = 2	ϕ Porosity																																																					
N	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
1												.061	.061	.061	.061	.060	.060	.060	.059	.058	.058	.057	.056																															
2											.062	.061	.061	.061	.061	.061	.060	.060	.059	.059	.058	.057	.056	.056																														
3										.062	.062	.062	.061	.061	.061	.061	.061	.060	.060	.059	.058	.057	.056	.056	.055																													
4									.062	.062	.062	.062	.062	.061	.061	.061	.061	.061	.060	.060	.059	.058	.056	.056	.055	.055																												
5								.062	.062	.062	.062	.062	.062	.062	.061	.061	.061	.061	.061	.060	.060	.058	.057	.056	.056	.055	.054																											
6							.062	.062	.062	.062	.062	.062	.062	.062	.062	.061	.061	.061	.061	.061	.060	.059	.058	.057	.056	.056	.055	.054	.054	.052	.050	.047	.046	.046	.046	.046	.046																	
7						.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.061	.061	.061	.061	.061	.060	.059	.058	.057	.056	.056	.055	.055	.054	.052	.049	.047	.046	.046	.046	.046	.046	.046	.046	.046	.046	.046											
8					.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.061	.061	.061	.061	.061	.060	.059	.058	.057	.056	.056	.055	.055	.054	.052	.049	.047	.046	.046	.046	.046	.046	.046	.046	.046	.046	.046	.046	.046	.046	.046	.046					
9				.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.061	.061	.061	.061	.061	.060	.059	.058	.057	.056	.056	.055	.054	.054	.052	.050	.049	.046	.046	.046	.046	.046	.046	.046	.046	.046	.046	.046	.046	.046	.046	.046				
10			.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.061	.061	.061	.061	.061	.060	.059	.058	.057	.056	.056	.055	.055	.054	.054	.054	.054	.054	.054	.054	.054	.054	.054	.054	.054	.054	.054	.054	.046	.046	.046	.046			
11		.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.061	.061	.061	.061	.050	.059	.059	.058	.056	.056	.056	.056	.056	.056	.056	.056	.056	.056	.056	.056	.056	.056	.056	.056	.056	.056	.054	.046	.046	.046	.046		
12	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.061	.061	.060	.060	.060	.060	.060	.060	.060	.060	.060	.060	.060	.060	.060	.060	.060	.060	.060	.060	.060	.060	.060	.058	.054	.046	.046	.046	.046	
13	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.060	.056	.054	.046	.046	.046	.046
14	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.060	.056	.054	.046	.046	.046
15	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.060	.056	.054	.046	.046	.046
16	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.060	.056	.054	.046	.046	
17																																.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.060	.056	.054	.046		
18																																					.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.062	.060	.056	.054	.046			

Table 2.6(d): Reservoir Porosity ϕ

K = 1	Sw-Water Saturation																																																				
J\I	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
1																																																						
2																																																						
3										.275																																												
4									.275	.275	.275																																											
5								.275	.275	.275	.275	.275																																										
6							.275	.275	.275	.275	.275	.275	.275																																									
7						.275	.275	.275	.275	.275	.275	.275	.275	.275																																								
8					.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275																																							
9				.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275																																						
10			.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275																																					
11		.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275																																				
12	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275																																			
13	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275							
14	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275						
15	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275						
16	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275						
17																																.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275						
18																																					.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275							

K = 2	Sw-Water Saturation																																																				
J\I	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
1												.278	.279	.280	.281	.282	.283	.285	.288	.291	.294	.298	.302																															
2											.276	.277	.278	.279	.280	.281	.282	.284	.286	.289	.293	.297	.302	.305																														
3										.275	.275	.276	.277	.278	.279	.280	.281	.282	.284	.287	.291	.297	.302	.305	.308																													
4									.275	.275	.275	.275	.276	.277	.278	.279	.280	.281	.282	.285	.289	.295	.302	.304	.307	.311																												
5								.275	.275	.275	.275	.275	.275	.276	.277	.278	.279	.280	.280	.282	.286	.291	.297	.302	.305	.309	.312																											
6							.275	.275	.275	.275	.275	.275	.275	.275	.276	.277	.278	.279	.279	.280	.282	.286	.291	.297	.302	.305	.309	.312	.316	.327	.342	.359	.373	.373	.373	.373	.373																	
7						.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.276	.277	.278	.279	.279	.280	.282	.286	.291	.296	.302	.305	.308	.312	.316	.329	.344	.360	.373	.373	.373	.373	.373	.373	.373	.373	.373	.373											
8					.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.276	.277	.278	.279	.279	.280	.282	.286	.291	.296	.302	.305	.308	.312	.316	.329	.344	.358	.373	.373	.373	.373	.373	.373	.373	.373	.373	.373	.373	.373	.373	.373	.373					
9				.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.276	.277	.278	.278	.279	.280	.282	.286	.291	.297	.302	.305	.309	.312	.316	.328	.338	.350	.373	.373	.373	.373	.373	.373	.373	.373	.373	.373	.373	.373	.373	.373	.373				
10			.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.276	.277	.277	.278	.279	.280	.282	.286	.291	.296	.302	.306	.309	.311	.316	.316	.316	.316	.316	.316	.316	.316	.316	.316	.316	.316	.316	.316	.316	.373	.373	.373	.373			
11		.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.276	.276	.277	.277	.278	.279	.282	.286	.290	.294	.302	.302	.302	.302	.302	.302	.302	.302	.302	.302	.302	.302	.302	.302	.302	.302	.302	.302	.316	.373	.373	.373	.373		
12	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.276	.276	.277	.278	.282	.292	.282	.282	.282	.282	.282	.282	.282	.282	.282	.282	.282	.282	.282	.282	.282	.282	.282	.282	.282	.302	.316	.373	.373	.373	.373	
13	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.282	.302	.316	.373	.373	.373	.373
14	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.282	.302	.316	.373	.373	.373
15	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.282	.302	.316	.373	.373	.373
16	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.292	.302	.316	.373	.373	
17																																.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.282	.302	.316	.373		
18																																					.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.275	.282	.302	.316	.373			

Table 2.6(e): Initial Water Saturation S_w

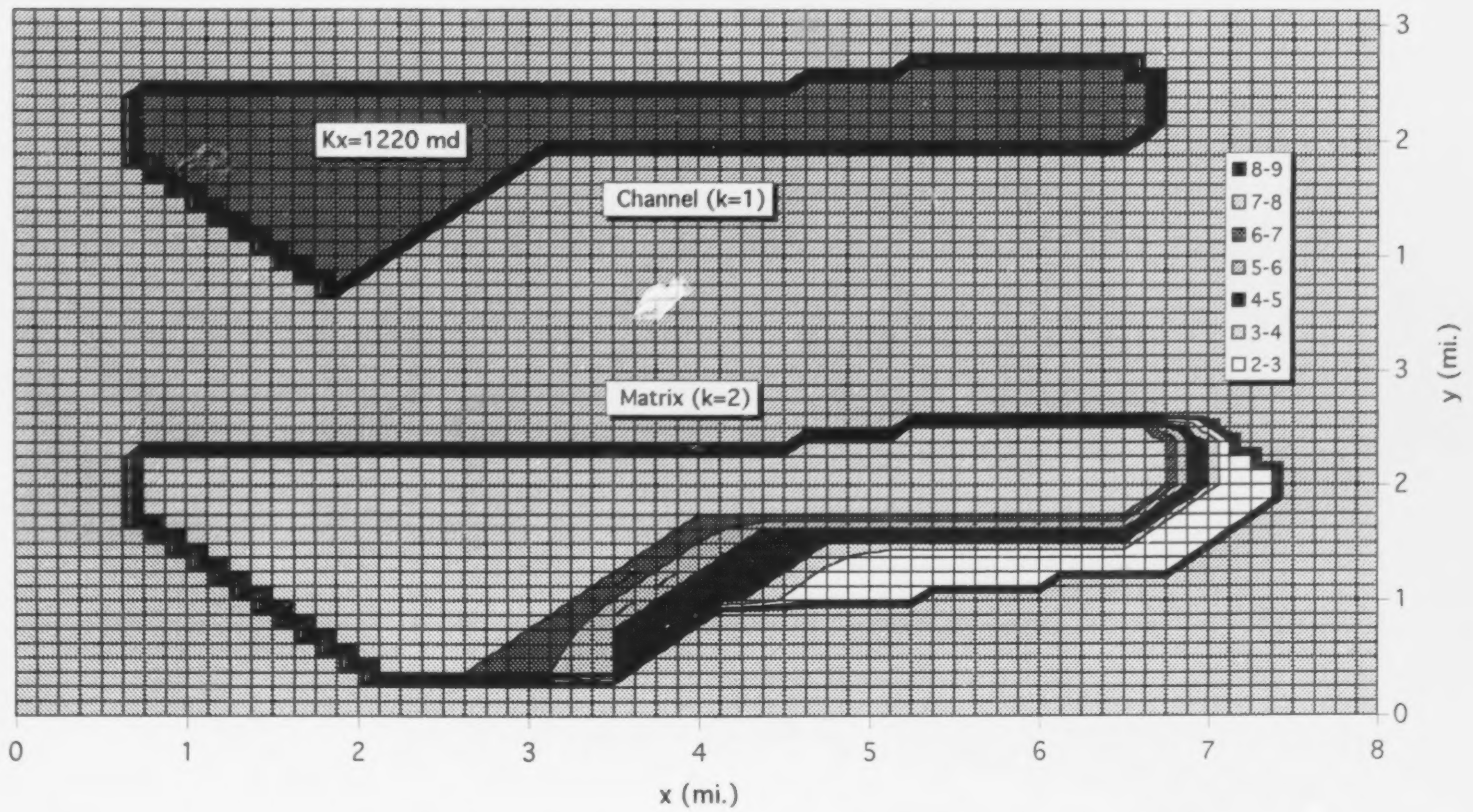


Figure 2.17(a): Reservoir Permeability Kx (md)

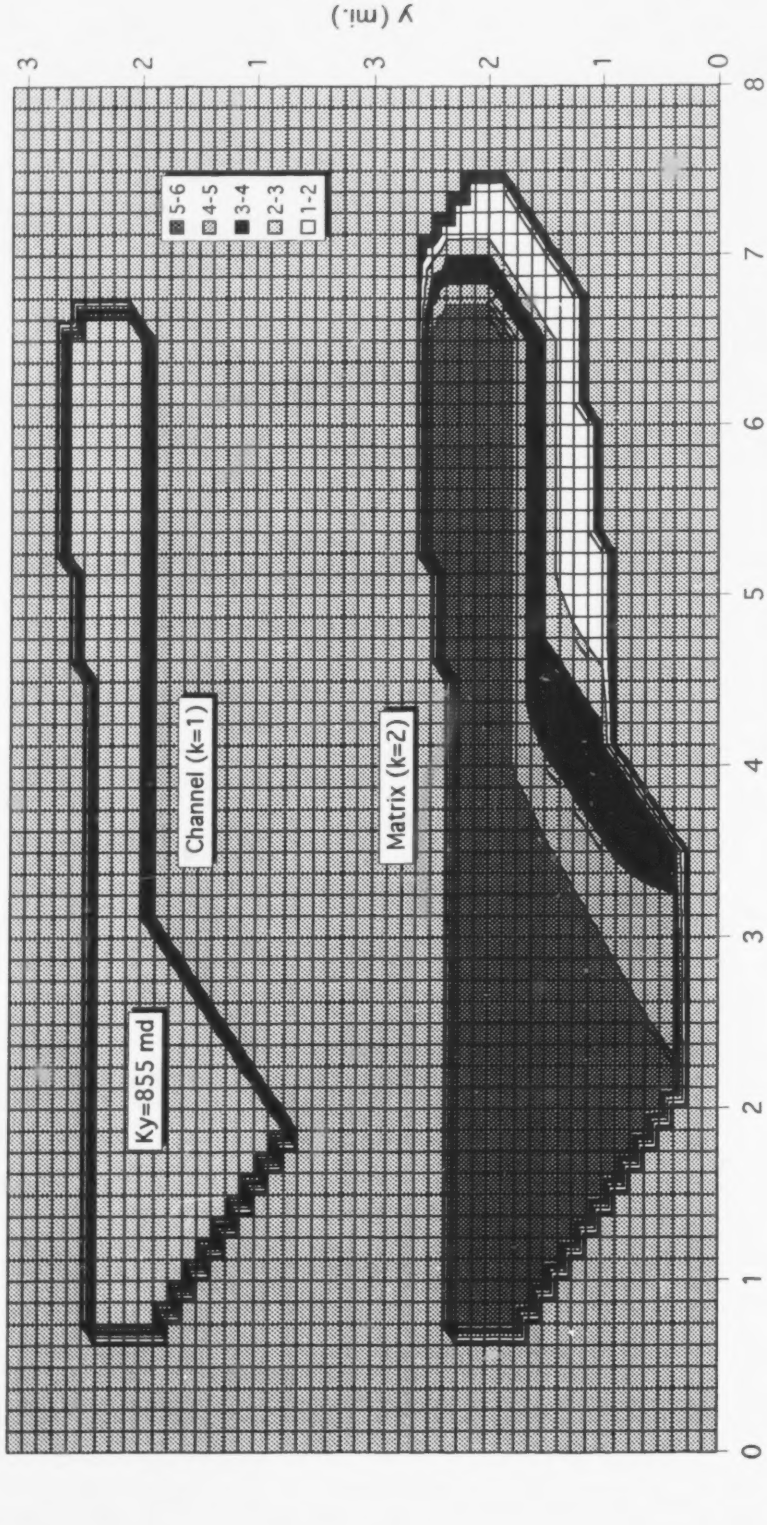


Figure 2.17(b): Reservoir Permeability Ky (md)

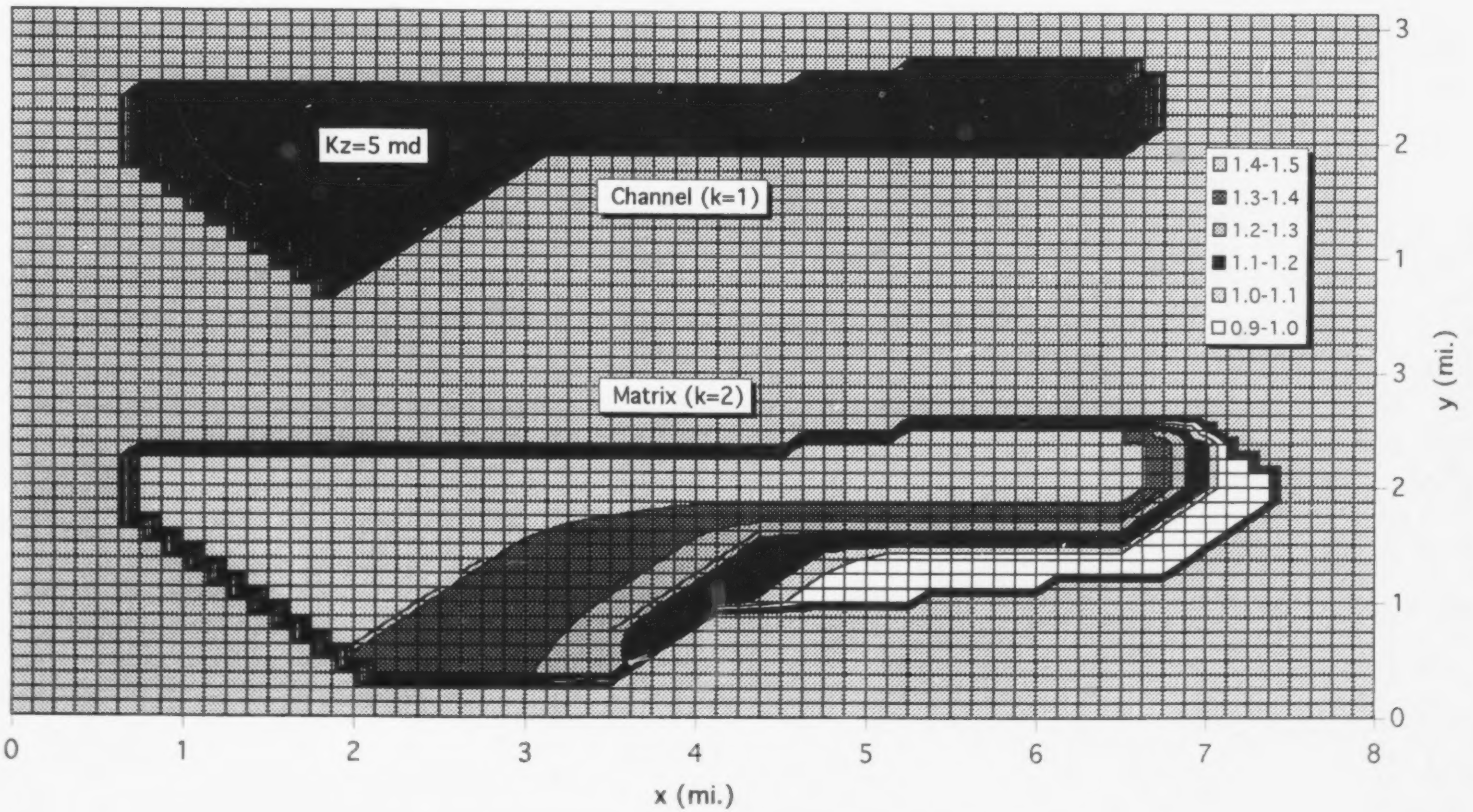


Figure 2.17(c): Reservoir Permeability Kz (md)

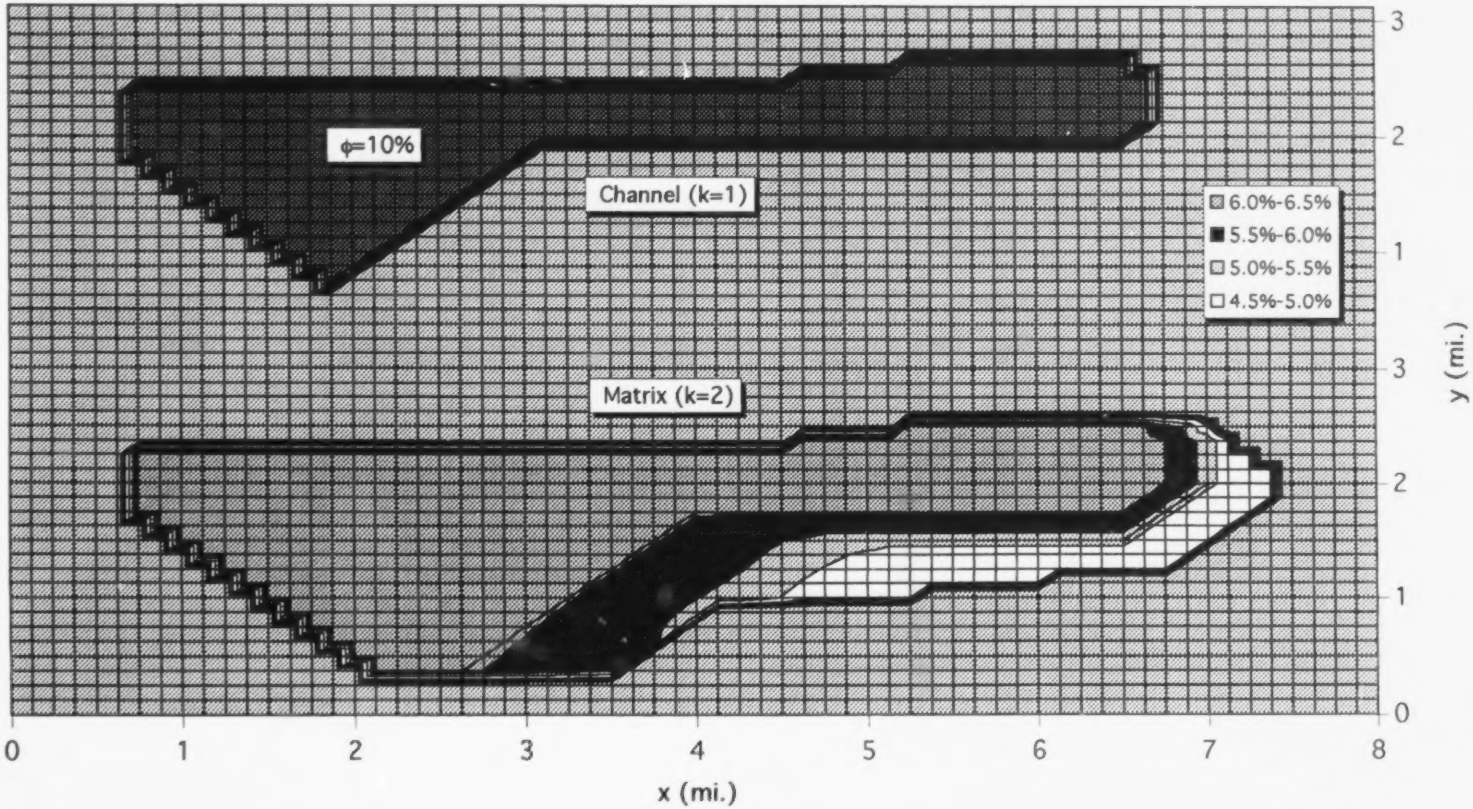


Figure 2.17(d): Reservoir Porosity φ

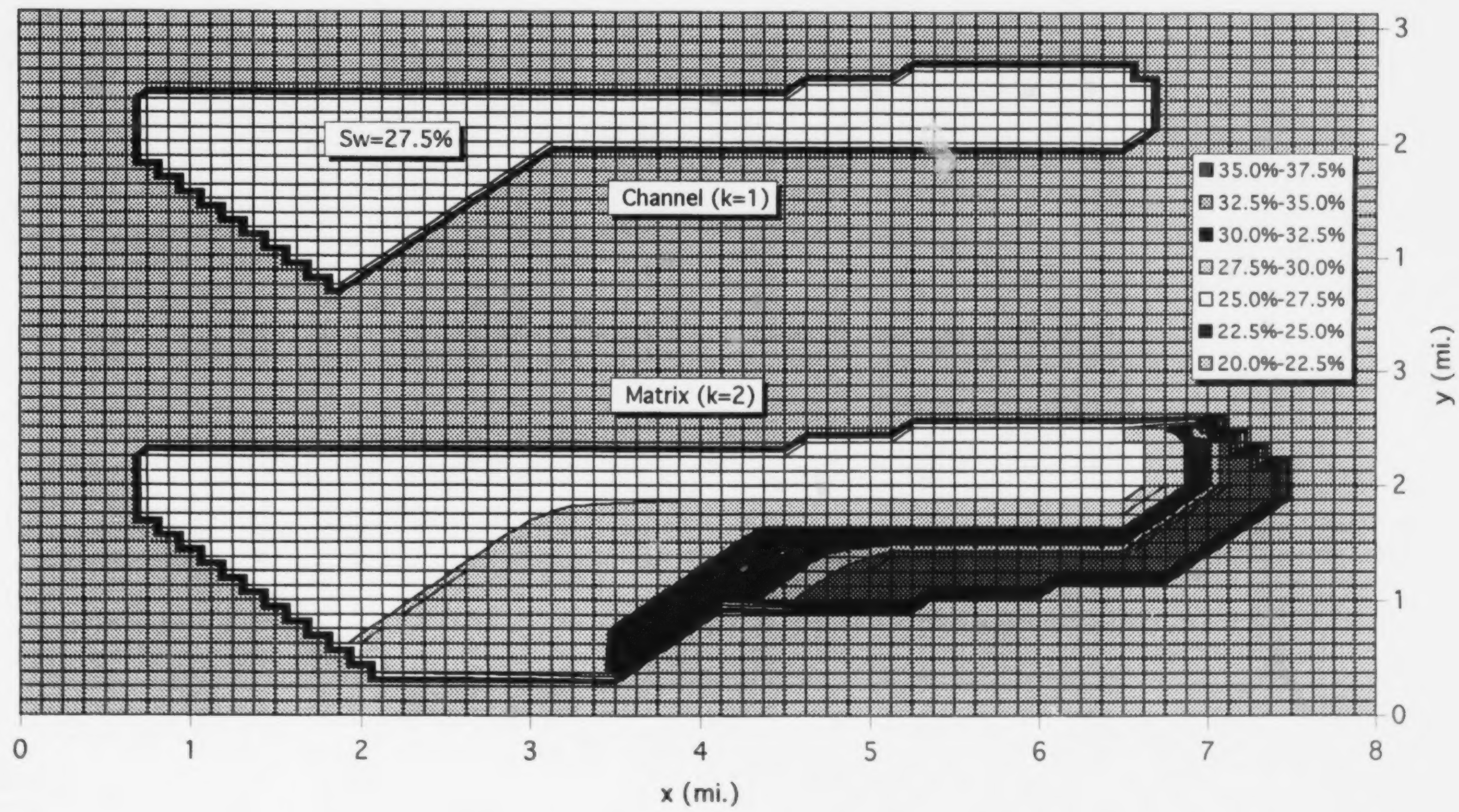


Figure 2.17(e): Initial (Oct-87) Water Saturation S_w

2.9 Pressure-Volume-Temperature Data

Oil is a liquid mixture containing many hydrocarbon fractions and inorganic compounds. Lighter fractions are more volatile and have lower boiling points than the heavier fractions. Lighter fractions tend to be in a free gaseous state at atmospheric pressure and room temperature. Table 2.7 lists the liquid and gas composition of Chedderville Viking "A" hydrocarbons at standard conditions (1 atm and 60° F) as provided by Canadian Hunter (1994). The gas was sampled from 06-14-37-7W5 located in a gas cap and the liquid was sampled down dip at 08-13-37-8W5. At typical reservoir pressures and temperatures, light fractions are soluble in the liquid mixture. The phase relationship[5] between liquid and vapour fractions depend on the composition, pressure and temperature. At thermodynamic equilibrium, each phase will have a unique composition of hydrocarbon fractions. Lighter fractions will concentrate in the vapour state and heavier fractions will concentrate in the liquid state. The liquid will be saturated with its ability to dissolve lighter fractions. As the pressure increases isothermally, the gaseous light fractions will dissolve more readily in the liquid mixture and the vapour fractions will decrease. At some critical pressure, all fractions will be in the liquid state. Above this critical pressure, the liquid will have an increased ability to dissolve more light fractions and will become undersaturated in the absence of a vapour fraction. The critical pressure at which the oil changes from undersaturated to saturated states is known as the bubble point pressure. This is the saturation pressure at which the first vapour bubble forms in the closed system. Black oil is a term used to characterize the liquid mixture as a single lumped component, with isothermal properties that depend on pressure only. Similarly, free gas refers to the lumped gaseous mixture, with isothermal properties that also depend on pressure only. Since the free gas is composed mostly of hydrocarbons, it will have a non-ideal gas compressibility factor. The solubility of gas in oil will depend on whether the system pressure is above or below the bubble point. The oil will have a compressibility factor that increases with solution gas, and therefore have different pressure dependence above and below the bubble point. Similarly, oil viscosity will also depend on the solution gas and have different pressure dependence for saturated and undersaturated states. Formation volume factors are used to relate the standard volume of a particular phase to the volume that results at reservoir pressure and temperature. For reservoir liquids of oil and formation water, the standard volume is one barrel of liquid at stock tank conditions (1 atm, 60° F). For free gas, the standard volume is one standard cubic foot (1 atm, 60° F). Oil and water formation volume factors will account for dissolved gas in solution. Gas solubilities are expressed in standard volumes of

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[5] Refer to Ahmed (1989) for a more comprehensive discussion on hydrocarbon phase behaviour.

Gas Analysis	06-14-37-7W5			
Gas Component	Mole Fraction	Molecular Mass	Psuedo-Critical p_{pc} (psia)	Psuedo-Critical T_{pc} (degrees F)
N2	0.30%	28.01	493.1	-232.5
CO2	0.90%	44.01	1071.0	87.9
C1	86.09%	16.04	666.4	-116.7
C2	7.71%	30.07	706.5	89.9
C3	3.20%	44.10	616.0	206.1
IC4	0.40%	58.12	527.9	274.5
nC4	0.90%	58.12	550.6	305.6
IC5	0.20%	72.15	490.4	369.1
nC5	0.20%	72.15	488.6	385.8
C6	0.10%	86.18	436.9	453.6
Mixture	100.00%	19.15	671.9	-82.5

Critical Constants: (Ahmed, T., Table 1.1, Figures 2.3-2.5)

Critical Constant Correction: Carr-Kobayashi-Burrows Method (Ahmed, T., p98)

Standard Conditions: 1 atm and 60 degrees F

Liquid Analysis	08-13-37-8W5					
Liquid Component	Mole Fraction	Mass Fraction	Volume Fraction	Molecular Mass	Psuedo-Critical p_{pc} (psia)	Psuedo-Critical T_{pc} (degrees F)
N2	0.11%	0.03%	0.03%	28.01	493.1	-232.5
CO2	0.70%	0.33%	0.28%	44.01	1071.0	87.9
C1	43.22%	7.42%	17.16%	16.04	666.4	-116.7
C2	7.90%	2.54%	4.93%	30.07	706.5	89.9
C3	5.44%	2.57%	3.51%	44.10	616.0	206.1
IC4	1.09%	0.68%	0.84%	58.12	527.9	274.5
nC4	2.82%	1.75%	2.08%	58.12	550.6	305.6
IC5	1.31%	1.01%	1.13%	72.15	490.4	369.1
nC5	1.56%	1.21%	1.33%	72.15	488.6	385.8
C6	1.98%	1.98%	2.08%	86.18	436.9	453.6
C7+	33.87%	80.48%	66.63%	222.50	300.0	-200.0
Mixture	100.00%	100.00%	100.00%	93.46	533.9	-68.9

Critical Constants: (Ahmed, T., Table 1.1, Figures 2.3-2.5) C7+ from Hydrocarbon Liquid Analysis (Average Boiling Point = 215.3 C, 37.3 API)

Critical Constant Correction: Carr-Kobayashi-Burrows Method (Ahmed, T., p98)

Standard Conditions: 1 atm and 60 degrees F

C7+ Liquid Analysis	08-13-37-8W5	
Component	Boiling Point C	Mole Fraction
Heptanes	68.9	2.11%
Octanes	98.3	2.25%
Nonanes	125.6	2.06%
Decanes	150.6	2.23%
Undecanes	173.9	1.98%
Dodecanes	196.1	1.73%
Tridecanes	215.0	1.71%
Tetradecanes	235.0	1.54%
Pentadecanes	252.2	1.34%
Hexadecanes	270.6	1.22%
Heptadecanes	287.8	0.94%
Octadecanes	302.8	1.06%
Nonadecanes	317.2	0.94%
Eicosanes	330.0	0.76%
Heneicosanes	344.4	0.71%
Docosanes	357.2	0.66%
Tricosanes	369.4	0.56%
Tetracosanes	380.0	0.51%
Pentacosanes	391.1	0.46%
Hexacosanes	401.7	0.36%
Heptacosanes	412.2	0.35%
Octacosanes	422.2	0.30%
Nonacosanes	431.7	0.27%
Tricontanes Plus	441.1	1.80%
Benzene	80.0	0.14%
Toluene	110.6	0.72%
Ethylbenzene, p+m-Xylene	136.1	1.58%
o-Xylene	144.4	0.76%
1,2,4 Trimethylbenzene	168.9	0.73%
Cyclopentane	48.9	0.05%
Methlycyclopentane	72.2	0.42%
Cyclohexane	81.1	0.68%
Methlycyclohexane	101.1	0.94%
Mixture	215.3	33.87%

Table 2.7 Gas Analysis (06-14-37-7W5) and Oil Analysis (08-13-37-8W5)

gas dissolved in standard volumes of liquid.

Mixture molecular weights (MW), pseudo-critical pressures (p_{pc}) and pseudo-critical temperatures (T_{pc}) were calculated for liquid from 08-13-37-8W5 (MW=93.5, p_{pc}=534 psia, T_{pc}=-69° F) and gas from 06-14-37-7W5 (MW=19.2, p_{pc}=672 psia, T_{pc}=-83° F) in Table 2.7 using molar-averaged critical constants (Ahmed, 1989, Table 1.1, Figures 2.3-2.5). Molar average boiling point (215.3° C) was calculated for the heavier liquid fractions (C7+) which correlated to 37.3 API gravity (MW=222.5, p_{pc}=300 psia, T_{pc}=-200° F). Mixture critical constant corrections for N_2 and CO_2 were performed using Carr-Kobayashi-Burrows method (Ahmed, 1989, p98). This analysis provides a basis for the range of hydrocarbons present in the gas cap and the oil deposit. Table 2.8 lists the gravity of oil sampled from different wells. No variation is observed in oil gravity.

Well	API	Oil Gravity (Water=1)
16-09-37-7W5	41.73	0.82
06-16-37-7W5	40.87	0.82
08-14-37-8W5	40.68	0.82
08-13-37-8W5	40.40	0.82

Table 2.8: Oil API and Gravity Measurements from Selected Wells

A Pressure-Volume-Temperature (PVT) laboratory analysis was provided by Canadian Hunter (1994) for the hydrocarbon fluids sampled from 08-13-37-8W5. The reported reservoir temperature was 185° F. The isothermal analysis included:

- oil and gas densities (ρ_o, ρ_g)
- gas deviation factor (z)
- oil and gas viscosities (μ_o, μ_g)
- oil and gas formation volume factors (B_o, B_g)
- solution gas-oil ratios (R_{so})

The initial bubble point pressure for the liquid sample was measured at p_b=3002.7 psia. Both flash and differential vaporization analysis was performed on the sample. The analysis presented herein has further extrapolated gas and saturated oil properties above the initial bubble point to cover a wider pressure range that includes possible waterflood repressurization hysteresis.

Properties of the liberated gas from the liquid sample were measured in the laboratory below the bubble point pressure. Table 2.9 tabulates both measured and extrapolated gas properties (differential vaporization). The liberated gas molecular weight (MW_a=23.3), pseudo-critical pressure (p_{pc}=660 psia) and pseudo-critical temperature (T_{pc}=-69° F) were fitted to extrapolate gas properties above the initial bubble point (p_b=3002.7 psia). The standard gas density and gas gravity were estimated at ρ_{scg}=0.0614 lbs/ft^3 and γ_g=0.805 (Air=1). The incremental gas deviation factor (z) was extrapolated using Hall-Yarborough method (Ahmed, 1989, p102-103, Dake, 1978, p19). The gas formation volume factor (B_g) was extrapolated using the non-ideal gas law with extrapolated gas deviation factors (Ahmed, 1989, p112, Dake, 1978, p45-50). The gas viscosity (μ_g) was extrapolated using Lee-Gonzalez-Eakin correlation (Ahmed, 1989, p120). The original laboratory measurements with extrapolated values for z, B_g and μ_g are plotted in Figures 2.18(a)-(c).

The measured oil API gravity was 40.4°. In this analysis, the oil was fitted with 41.5 API to extrapolate saturated oil behaviour above the initial bubble point in Table 2.10. The standard oil density and oil gravity were estimated at ρ_{sco}=51.06 lbs/ft^3 and γ_o=0.82 (Water=1). Undersaturated oil properties were measured in the laboratory above the initial bubble point pressure. The analysis presented herein approximates undersaturated oil behaviour using average slopes with respect to pressure. The values of these slopes for gas-oil solubility (R_{so}), oil formation volume factor (B_o) and oil viscosity (μ_o) are:

$$\frac{\partial R_{so}}{\partial p} = 0 \quad , \quad \frac{\partial B_o}{\partial p} = -1.84\times10^{-5} \quad , \quad \frac{\partial \mu_o}{\partial p} = 5.17\times10^{-5} \qquad p \geq p_b$$

The saturated gas-oil solubility (R_{so}) was extrapolated above the initial bubble point using Vasquez-Beggs' correlation (Ahmed, 1989, p177-181). The saturated oil formation volume factor (B_o) was extrapolated using Vasquez-Beggs' compressibility coefficient correlation (Ahmed, 1989, p162). The saturated oil viscosity (μ_o) was extrapolated using Beggs-Robinson Correlation (Ahmed, 1989, p210) with a 0.0416 cp correction to preserve continuity. The original laboratory measurements with extrapolated values for R_{so}, B_o and μ_o are graphed in Figures 2.19(a)-(c). The undersaturated oil properties are characterized by a family of parallel lines stemming from possible bubble points on the saturated oil curve. This reflects that the local bubble point pressure may vary as free gas is produced and that waterflood repressurization may create some hysteresis.

The solubility of gas in oil will depend on whether the reservoir pressure is above or below the bubble point pressure. When the reservoir pressure drops below the bubble point pressure, a free gas saturation will form. Oil will be saturated with dissolved gas. Saturated oil will behave differently from its undersaturated counterpart. The slope of oil properties with respect to pressure is discontinuous at the bubble point. When the free gas saturation exceeds the critical gas saturation, it will become mobile. Migration of free gas will change the local ratio of free gas to oil volumes. The change in vapour-liquid equilibrium will change the local saturation pressure (bubble point). The new bubble point can be estimated as the pressure which completely dissolves the local volumes of free and dissolved gas in the local volume of oil. An isobaric increase in free gas saturation will tend to shift the bubble point up, while an isobaric decrease in free gas saturation will tend to shift the bubble point down. Since the presence of free gas implies that the oil is locally saturated, the bubble point can be dynamically tracked using the saturated gas-oil solubility relationship with pressure. New bubble point pressures can be interpolated directly from Table 2.10. When primary production is in a global pressure decline below the original bubble point, the relevant range of saturated PVT data will not be affected by a bubble point that varies above system pressure. If however, the reservoir is repressured by waterflood, the initial bubble point will no longer apply for the anticipated transition from saturated to undersaturated regimes. The undersaturated oil property pressure dependence will shift along the saturated curve. This is the hysteresis in bubble point pressure that occurs when the reservoir is repressurized after free gas is produced.

Formation water PVT was estimated in Table 2.11 using the salinity (4.5%) reported in the Canadian Hunter Chedderville Waterflood Design Study (1993). The saline water gravity was approximated using 45000 ppm NaCl (Bateman, R.M., Table 16.2 p315). The standard water density and water gravity were estimated at ρ_{scw}=64.3 lbs/ft^3 and γ_w=1.03 (Fresh Water=1). Gas-water solubility (R_{sw}) was correlated to water salinity and gas properties using the Hewlett-Packard H.P.41C Petroleum Fluids PAC Manual, 1982 (Ahmed, 1989, p202) with linear extrapolation above 6014.7 psia. Saline water formation volume factor (B_w) was also correlated using the Hewlett-Packard H.P.41C Petroleum Fluids PAC Manual, 1982 (Ahmed, 1989, p203). Saline water viscosity (μ_w) pressure dependence was obtained from Chesnut (unpublished), Shell Development Co. chart correlation (Matthews, 1967., p158). The correlated values for R_{sw}, B_w and μ_w are shown in Figures 2.20(a)-(c).

Gas Properties	08-13-37-8W5		
Standard Gas Density ρ_{gsc} (lbs/ft^3)	Gas Gravity γ_g (Air=1)		
0.0614	0.805		
Temperature T (degrees F)	Psuedo-Critical T_{pc} (degrees F)	Psuedo-Critical p_{pc} (psia)	Molecular Weight MW_a
185	-69	660	23.3
Pressure p (psia)	Gas Deviation Factor Z	Gas FVF B_g (rcf/scf)	Gas Viscosity μ_g (cp)
14.7	1.000	1.245420	0.0101
314.7	0.937	0.054510	0.0123
614.7	0.913	0.027180	0.0132
914.7	0.893	0.017870	0.0140
1214.7	0.876	0.013200	0.0148
1514.7	0.863	0.010430	0.0157
1814.7	0.852	0.008590	0.0167
2114.7	0.844	0.007300	0.0178
2414.7	0.841	0.006370	0.0190
2714.7	0.844	0.005690	0.0205
3002.7	0.852	0.005175	0.0219
3114.7	0.856	0.005013	0.0224
3214.7	0.861	0.004881	0.0229
3514.7	0.876	0.004543	0.0243
4014.7	0.907	0.004121	0.0267
4514.7	0.945	0.003817	0.0291
5014.7	0.987	0.003587	0.0313
5514.7	1.031	0.003408	0.0334
6014.7	1.077	0.003264	0.0354
6514.7	1.124	0.003145	0.0374
7014.7	1.171	0.003045	0.0393
7514.7	1.219	0.002959	0.0411
8014.7	1.268	0.002885	0.0428
8514.7	1.317	0.002819	0.0445
9014.7	1.365	0.002761	0.0462

Critical Contants and Molecular Weight fitted to extrapolate gas properties above bubble point p_b=3002.7 psia

Z-Factor Extrapolation: Hall-Yarborough Method (Ahmed, T., p102-103, Dake, L.P., p19)

Gas FVF Extrapolation: (Ahmed, T., p112, Dake, L.P., p45-50)

Gas Viscosity Extrapolation: Lee-Gonzalez-Eakin Correlation (Ahmed, T., p120)

Standard Conditions: 1 atm and 60 degrees F

Table.2.9: Isothermal Gas Properties

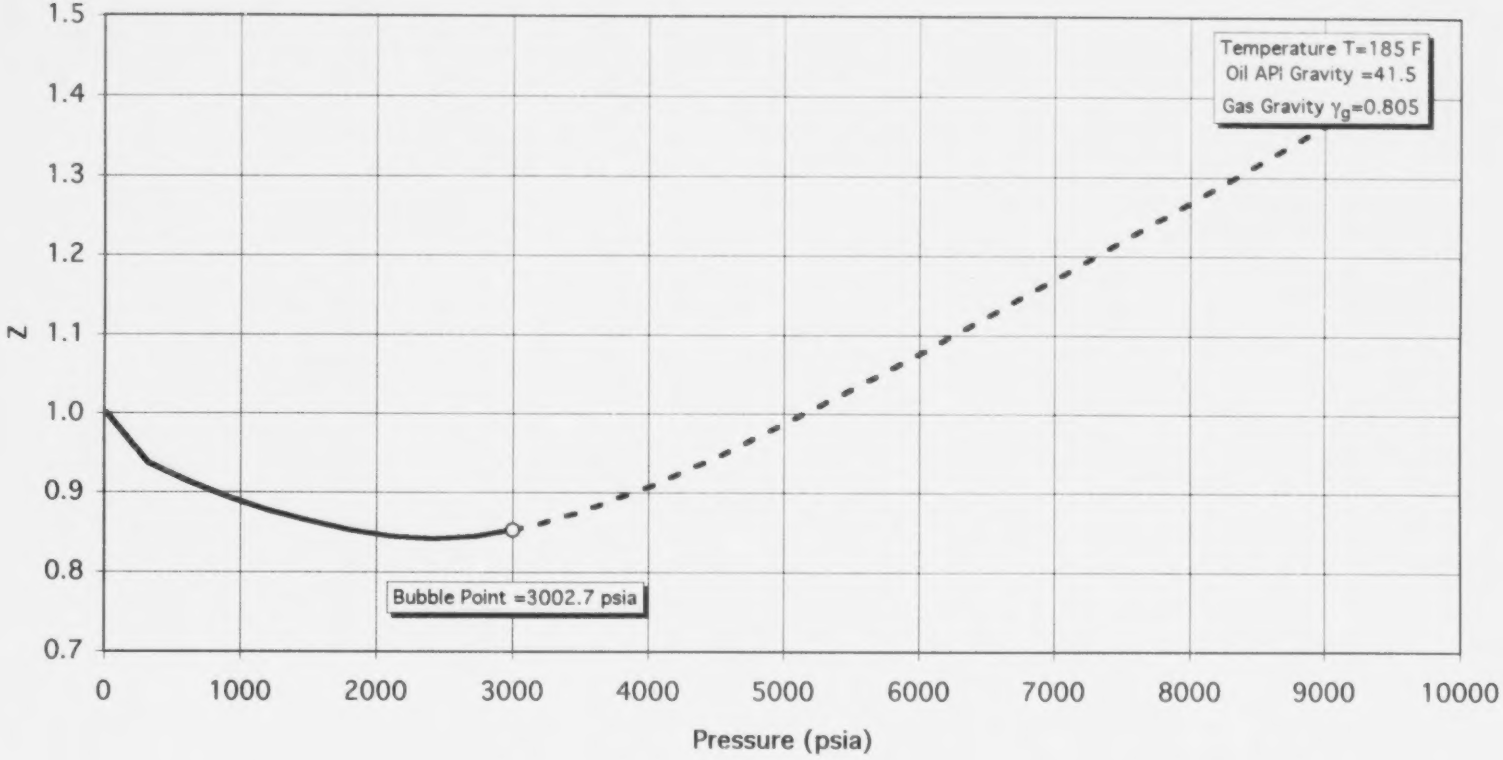

Figure 2.18(a): Gas Deviation Z-Factor (08-13-37-8W5)

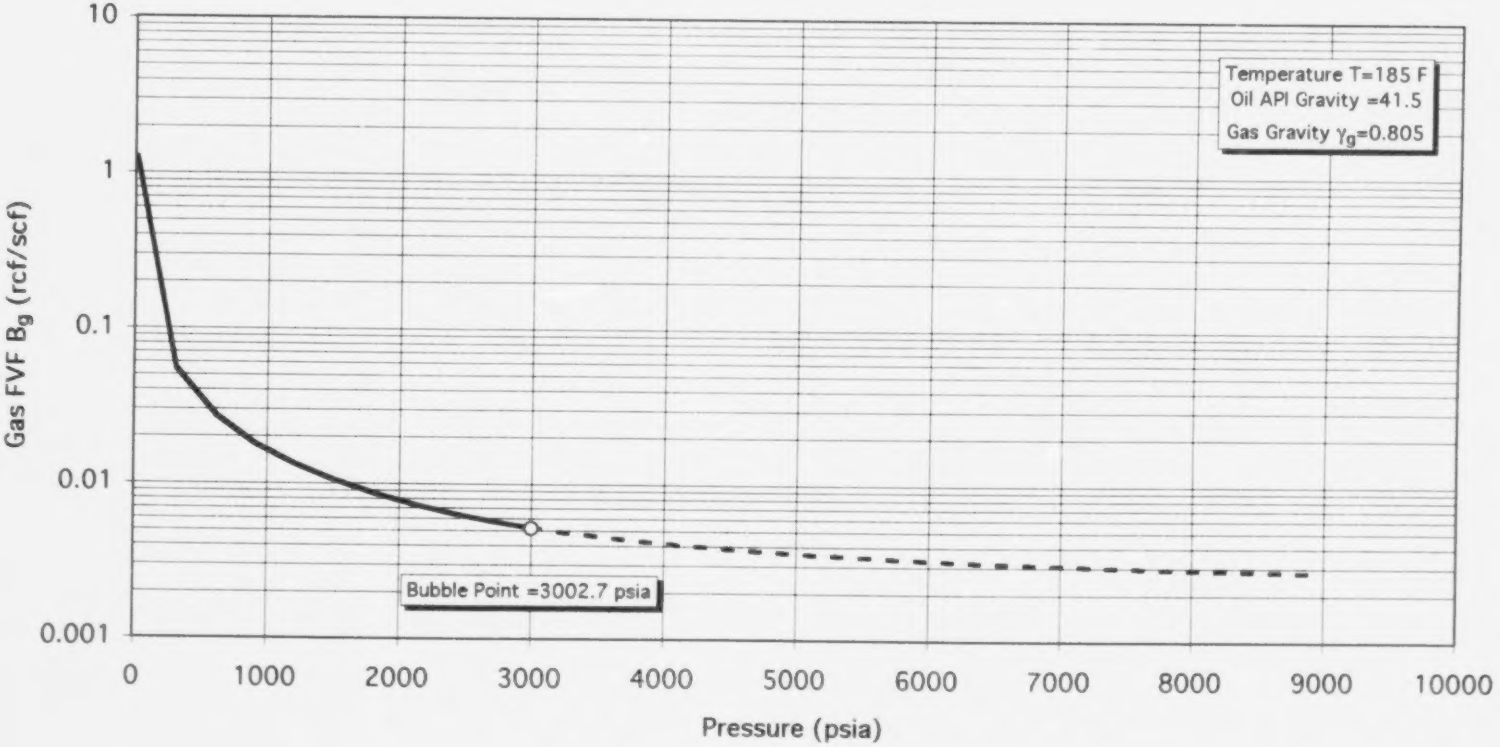

Figure 2.18(b): Gas Formation Volume Factor B_g (08-13-37-8W5)

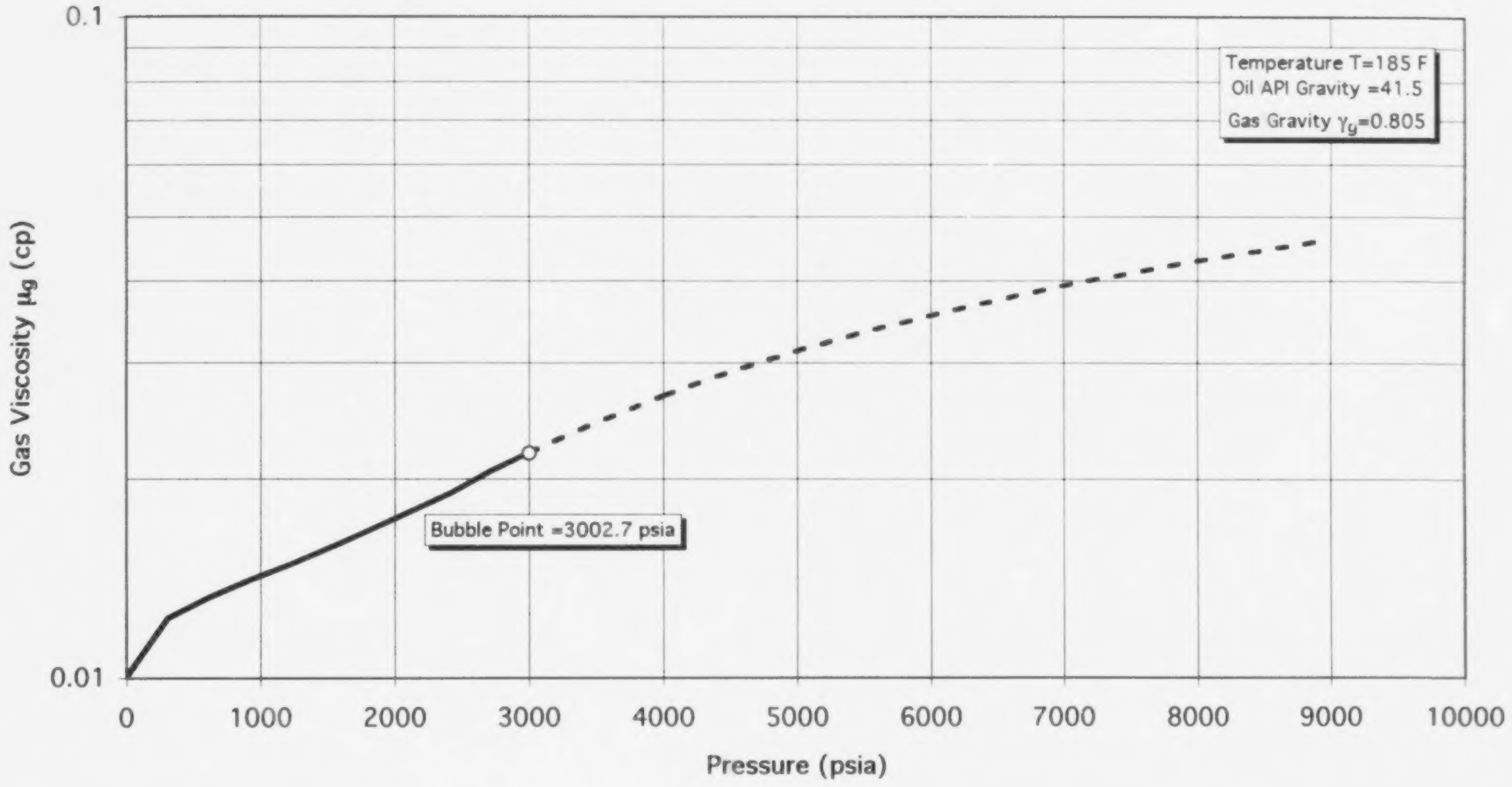

Figure 2.18(c): Gas Viscosity μ_g (08-13-37-8W5)

Oil Properties	08-13-37-8W5		
Standard Oil Density ρ_{osc} (lbs/ft^3)	Oil Gravity γ_o (Fresh Water=1)		
51.06	0.82		
Temperature T (Degrees F)	Gas Gravity γ_g (Air=1)	Oil Gravity (API)	Initial Solution GOR R_{so} (scf/STB)
185	0.805	41.5	893
	Undersaturated Oil Property Slopes above Bubble Point		
Bubble Point Pressure p_b (psia)	Gas-Oil Solubility dR_{so}/dp (scf/STB/psi)	Oil FVF dB_o/dp (RB/STB/psi)	Oil Viscosity $d\mu_o/dp$ (cp/psi)
3002.7	0	-1.84e-05	5.17e-05
	Saturated Oil Properties		
Pressure p (psia)	Gas-Oil Solubility R_{so} (scf/STB)	Oil FVF B_o (RB/STB)	Oil Viscosity μ_o (cp)
14.7	0	1.0630	1.5460
314.7	162	1.1750	1.0540
614.7	242	1.2130	0.9210
914.7	317	1.2460	0.8010
1214.7	391	1.2780	0.6990
1514.7	470	1.3120	0.6290
1814.7	548	1.3450	0.5610
2114.7	630	1.3800	0.5120
2414.7	714	1.4160	0.4720
2714.7	803	1.4550	0.4420
3002.7	893	1.4960	0.4260
3114.7	934	1.5154	0.4169
3214.7	970	1.5324	0.4095
3514.7	1078	1.5840	0.3893
4014.7	1263	1.6717	0.3611
4514.7	1452	1.7615	0.3379
5014.7	1644	1.8532	0.3185
5514.7	1841	1.9466	0.3020
6014.7	2040	2.0416	0.2878
6514.7	2243	2.1381	0.2753
7014.7	2449	2.2360	0.2644
7514.7	2658	2.3352	0.2546
8014.7	2869	2.4356	0.2459
8514.7	3083	2.5372	0.2380
9014.7	3299	2.6400	0.2308

Oil Gravity: Fitted for extrapolation of saturated oil properties above bubble point p_b=3002.7 psia

Gas-Oil Solubility: Extrapolation using Vasquez-Beggs' correlation (Ahmed, T., p177-181)

Saturated Oil FVF: Extrapolation using Vasquez-Beggs' compressibility coefficient correlation (Ahmed, T., p162)

Undersaturated Oil FVF: Linear extrapolation using flash liberation slope

Saturated Oil Viscosity: Extrapolation using Beggs-Robinson Correlation (Ahmed, T., p210) with .0416 cp correction

Undersaturated Oil Viscosity: Linear extraploation

Standard Conditions: 1 atm and 60 degrees F

Table 2.10: Isothermal Oil Properties

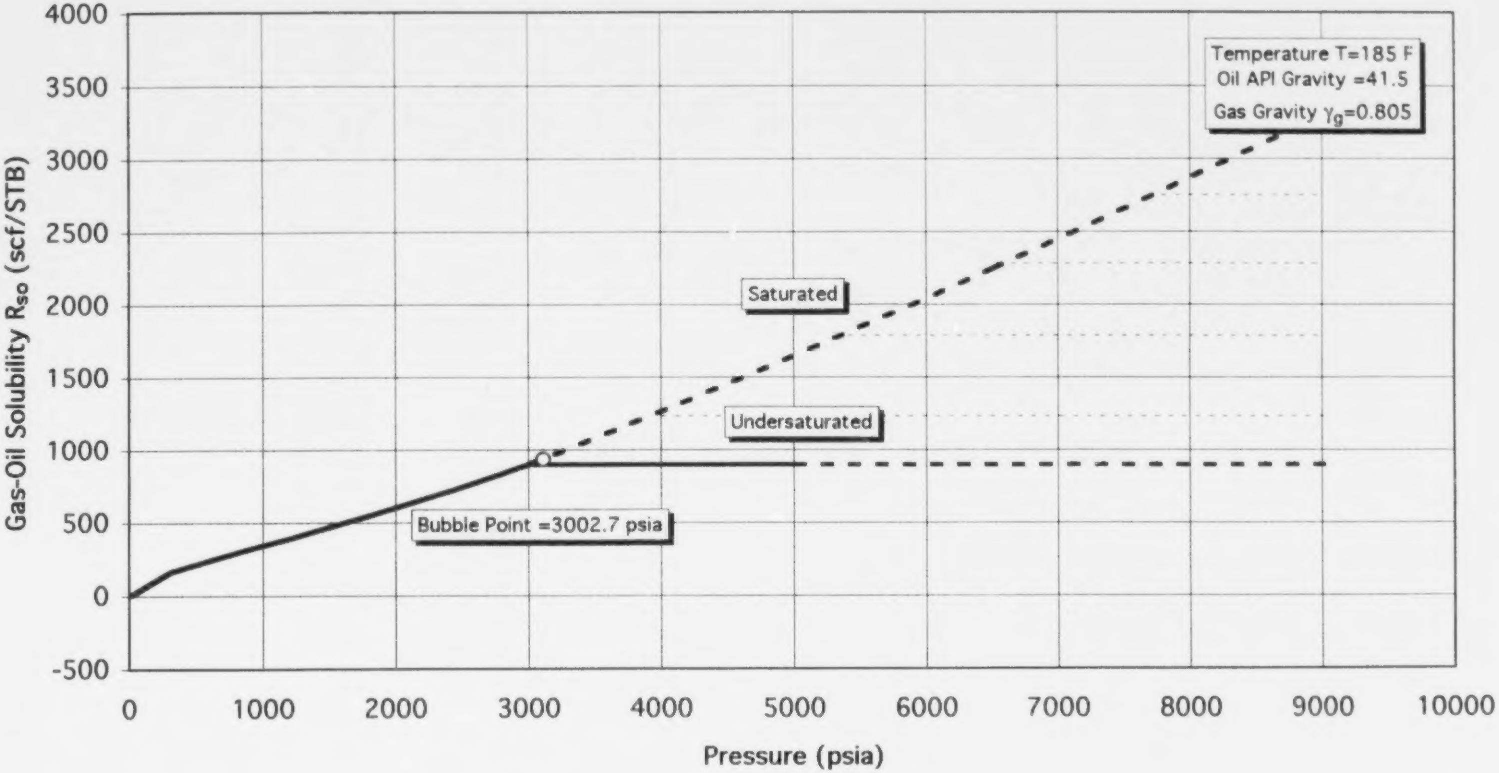

Figure 2.19(a): Gas-Oil Solubility R_{so} (08-13-37-8W5)

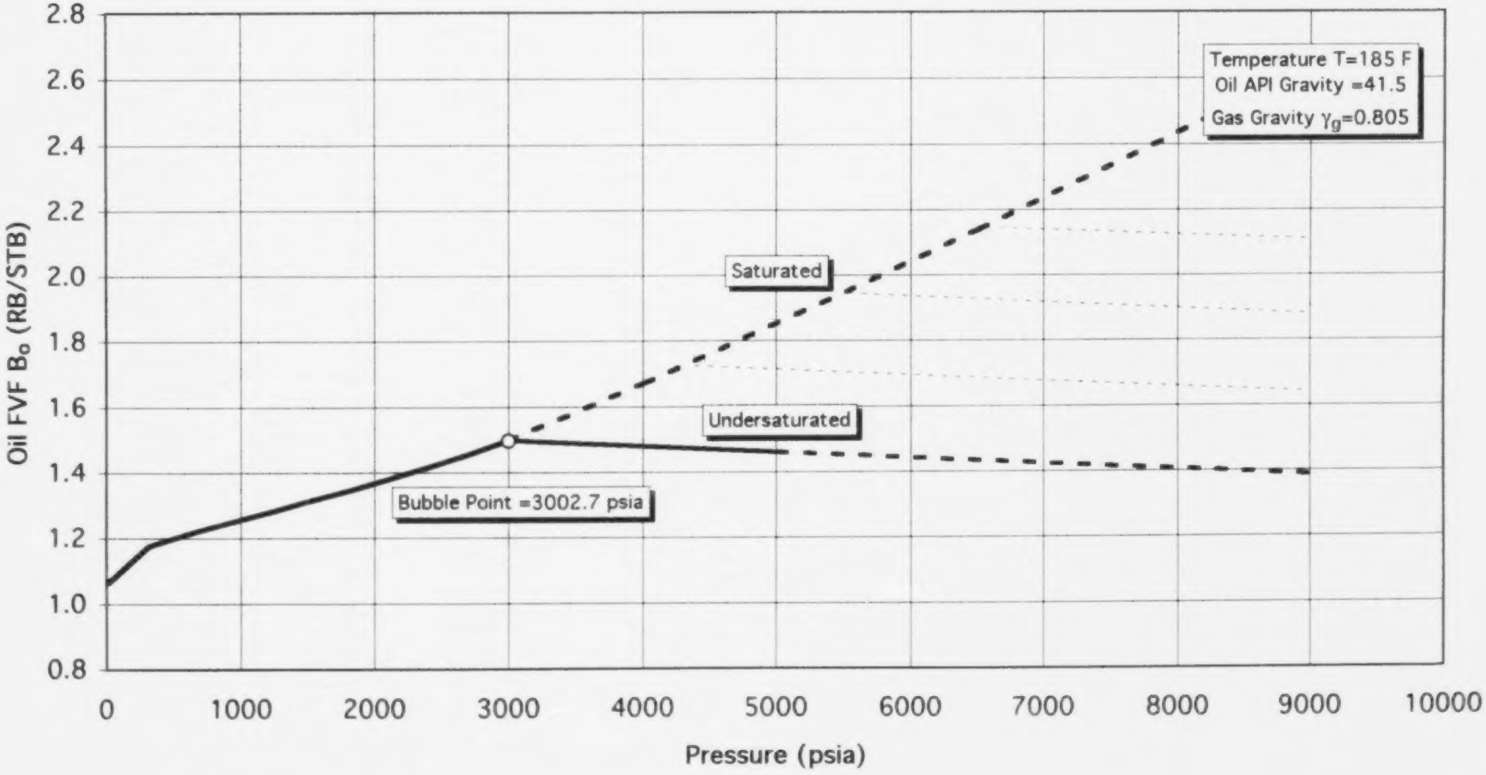

Figure 2.19(b): Oil Formation Volume Factor B_o (08-13-37-8W5)

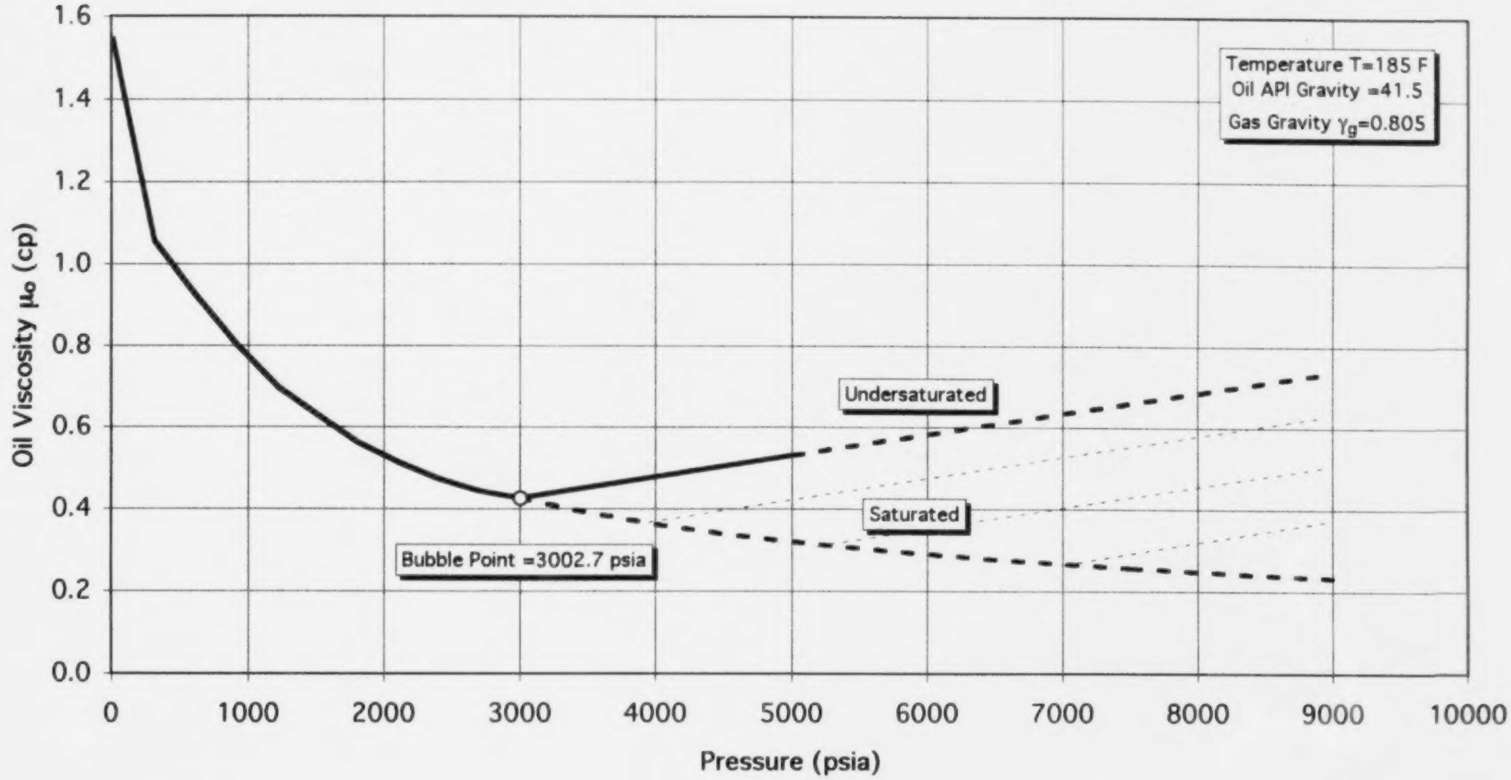

Figure 2.19(c): Oil Viscosity μ_o (08-13-37-8W5)

Water Properties	08-17-37-7W5		
Standard Water Density ρ_{wsc} (lbs/ft^3)	Water Gravity γ_w (Fresh Water=1)		
64.30	1.030		
Temperature T (Degrees F)	Gas Gravity γ_g (Air=1)	Water Salinity	Water Viscosity μ_w (cp) @3114.7 psia
185	0.805	4.5%	0.370
Pressure p (psia)	Gas-Water Solubility R_{sw} (scf/STB)	Water FVF B_w (RB/STB)	Water Viscosity μ_w (cp)
14.7	1.6	1.0214	0.367
314.7	3.4	1.0209	0.367
614.7	5.0	1.0204	0.367
914.7	6.6	1.0199	0.368
1214.7	8.1	1.0195	0.368
1514.7	9.5	1.0190	0.368
1814.7	10.8	1.0186	0.368
2114.7	12.0	1.0181	0.369
2414.7	13.1	1.0177	0.369
2714.7	14.2	1.0172	0.369
3002.7	15.1	1.0168	0.370
3114.7	15.4	1.0166	0.370
3214.7	15.7	1.0165	0.370
3514.7	16.5	1.0161	0.370
4014.7	17.6	1.0153	0.371
4514.7	18.5	1.0146	0.372
5014.7	19.1	1.0139	0.373
5514.7	19.5	1.0133	0.373
6014.7	19.6	1.0126	0.374
6514.7	19.7	1.0119	0.376
7014.7	19.8	1.0113	0.377
7514.7	20.0	1.0106	0.378
8014.7	20.1	1.0100	0.379
8514.7	20.2	1.0094	0.381
9014.7	20.3	1.0087	0.383

Water Salinity: Canadian Hunter Chedderville Waterflood Design Study, Hycal Energy Research Laboratories Ltd., Calgary, Oct 25, 1993.

Saline Gas-Water Solubility: Hewlett-Packard H.P.41C Petroleum Fluids PAC Manual, 1982 (Ahmed, T., p202), Linear extrapolation above 6014.7 psia

Saline Water FVF: Hewlett-Packard H.P.41C Petroleum Fluids PAC Manual, 1982 (Ahmed, T., p203)

Saline Water Viscosity: Pressure dependence from Chesnut, unpublished, Shell Development Co. (Matthews, C.S., p158) chart correlation

Water Gravity: γ_w=1.03 for 45000 ppm NaCl (Table 16.2 Bateman, R.M., p315)

Standard Conditions: 1 atm and 60 degrees F

Table 2.11: Isothermal Water Properties

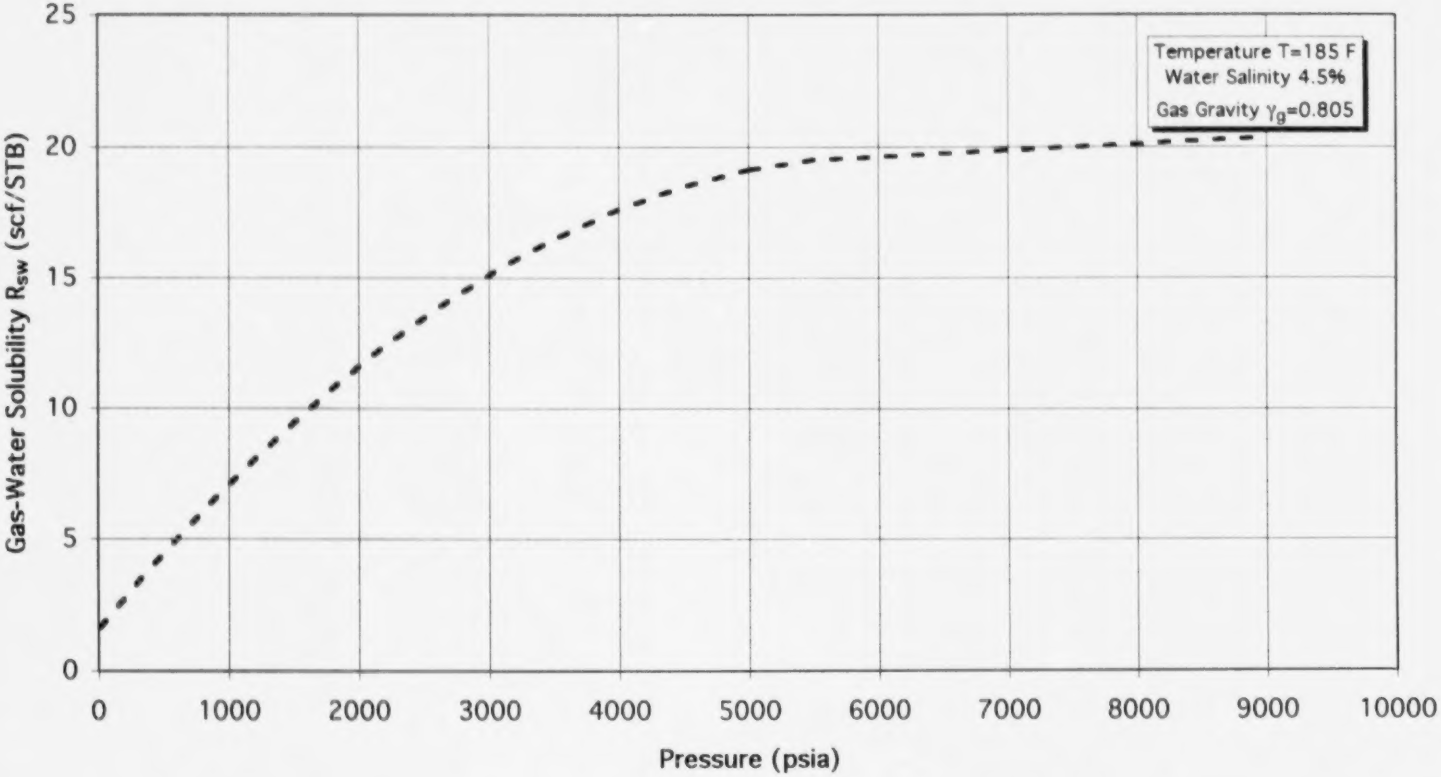

Figure 2.20(a): Gas-Water Solubility R_{sw} (08-17-37-8W5)

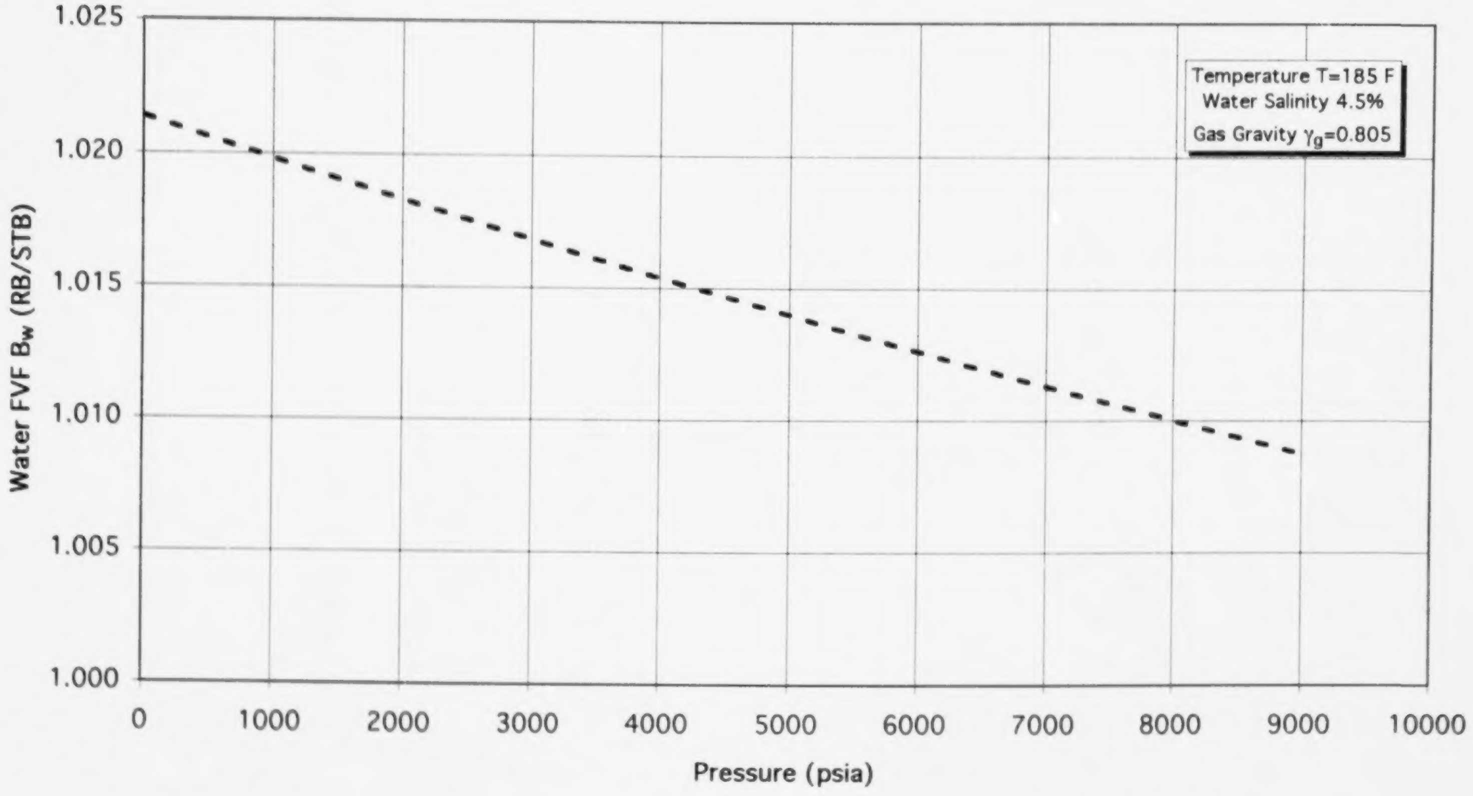

Figure 2.20(b): Water Formation Volume Factor B_w (08-17-37-8W5)

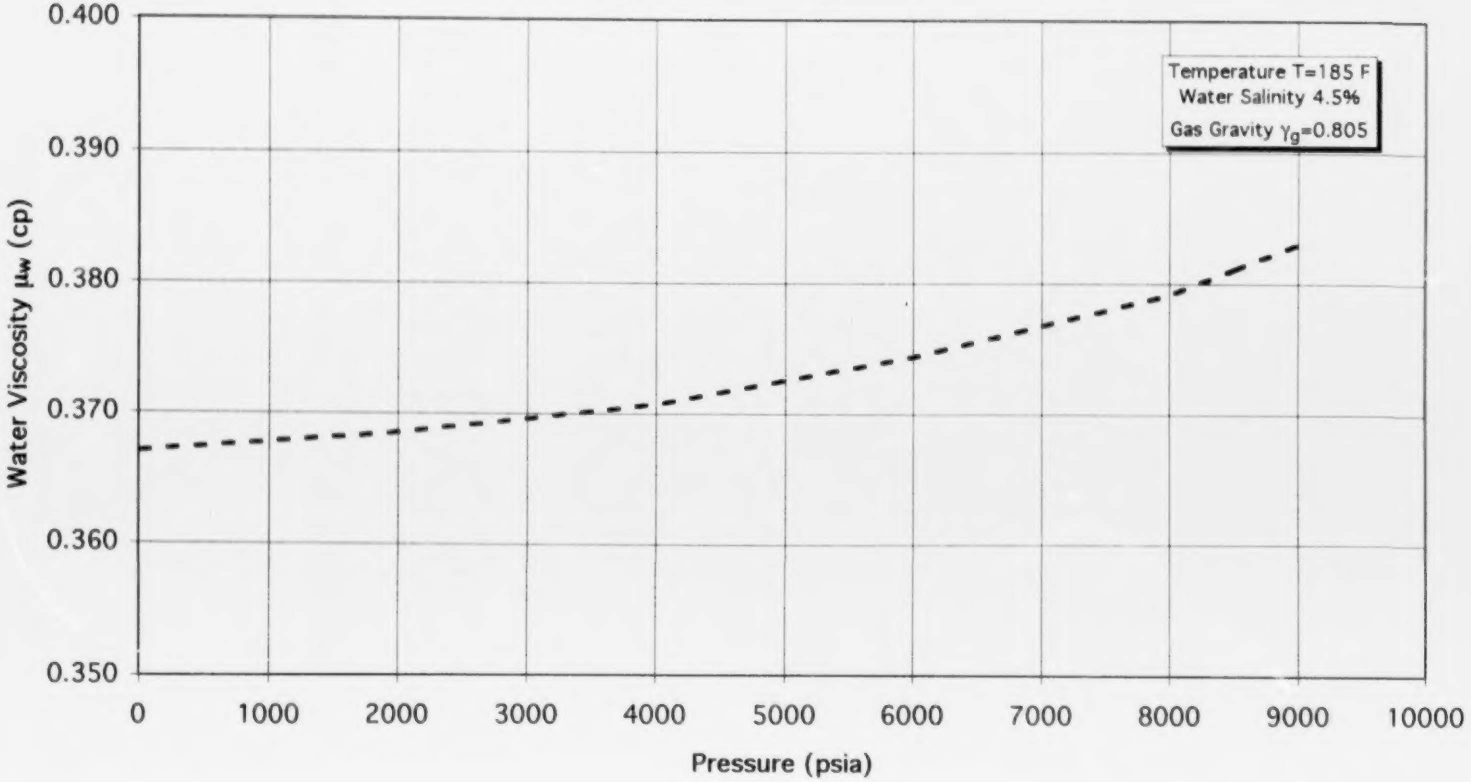

Figure 2.20(c): Water Viscosity μ_w (08-17-37-8W5)

2.10 Capillary Pressure Data

Fluids in porous media flow towards regions of lower potential. The fluid potential is the combined hydrodynamic and hydrostatic head. Generally, all three constituent phases of oil, water and free gas coexist in the porous reservoir. Each phase has its own potential. Phase potentials are interrelated by capillary pressures. Capillary pressures measure the difference between oil-water and oil-gas pressures caused by the interfacial tension between immiscible phases occupying distinct portions of the pore space. In the absence of capillary pressure, all three phases would be fully mixed. The oil-water and gas-oil capillary pressures (P_{cow}, P_{cgo}) are functions of water saturation and gas saturation, respectively. The oil-water capillary pressure (P_{cow}) decreases from an asymptotic limit at the irreducible water saturation (distinct simply-connected oil and water regions) to zero at high water saturation (oil fully dispersed in water). In contrast, the gas-oil capillary pressure (P_{cgo}) is small at low trapped gas saturations (gas fully dispersed in oil) and approaches an asymptotic limit at higher gas saturations (simply connected oil and gas regions).

Oil-water capillary pressure (P_{cow}) data was obtained from the Canadian Hunter Chedderville Waterflood Design Study (1993). Table 2.12 shows the analysis conducted on two core slices, 9B and 13B, sampled from 08-17-37-7W5. The rock was classified as neutral to moderately water-wet. The oil-water capillary pressure dependence on water saturations shows some hysteresis between imbibition and drainage curves (Figure 2.21). Core 9B was selected as the basis for the simulation model because its range of imbibition data seemed to be more consistent with the bulk of irreducible water estimates (Section 2.7) and relative permeability data (Section 2.11). The simulation model data extended the water range from S_w=27.5% (irreducible water) to S_w= 82.5% (residual oil). Gas-oil capillary pressure was not available and assumed to be negligible (P_{cgo}=0).

Core:	9B	Core:	13B
Well	08-17-37-7W5	Well	08-17-37-7W5
Depth KB (ft)	8535.1	Depth KB (m)	8536.3
Air Kx (md)	68	Air Kx (md)	15
Porosity	10.70%	Porosity	8.20%

Moderately Water-Wet	Neutral Wettability

Sw	Pcow (psi)	Sw	Pcow (psi)
29.40%	-0.29	34.70%	-0.26
44.50%	-0.81	40.50%	-0.73
55.30%	-2.50	46.30%	-2.22
59.60%	-5.11	49.20%	-4.54
68.20%	-11.48	52.00%	-10.21
72.30%	-20.41	55.90%	-18.16
72.30%	-27.00	55.90%	-24.02
71.20%	0.29	54.90%	0.26
68.20%	0.81	54.00%	0.73
59.70%	2.50	50.10%	2.22
49.10%	5.11	46.30%	4.54
40.60%	11.48	42.40%	10.21
30.00%	20.41	38.50%	18.16
28.00%	27.00	38.50%	24.02

Sw	* Pcow (psi)
27.50%	27.00
30.00%	20.41
32.50%	18.18
35.00%	15.95
37.50%	13.71
40.00%	11.48
42.50%	9.66
45.00%	7.84
47.50%	6.02
50.00%	4.82
52.50%	4.24
55.00%	3.66
57.50%	3.08
60.00%	2.50
62.50%	2.02
65.00%	1.53
67.50%	1.05
70.00%	0.55
72.50%	0.20
75.00%	0.01
77.50%	0.00
80.00%	0.00
82.50%	0.00

Canadian Hunter Chedderville Waterflood Design Study, Hycal Energy Research Laboratories Ltd., Calgary, Oct 25, 1993.

***Core 9B Basis for Waterflood Model**

Table 2.12: Oil-Water Capillary Pressure

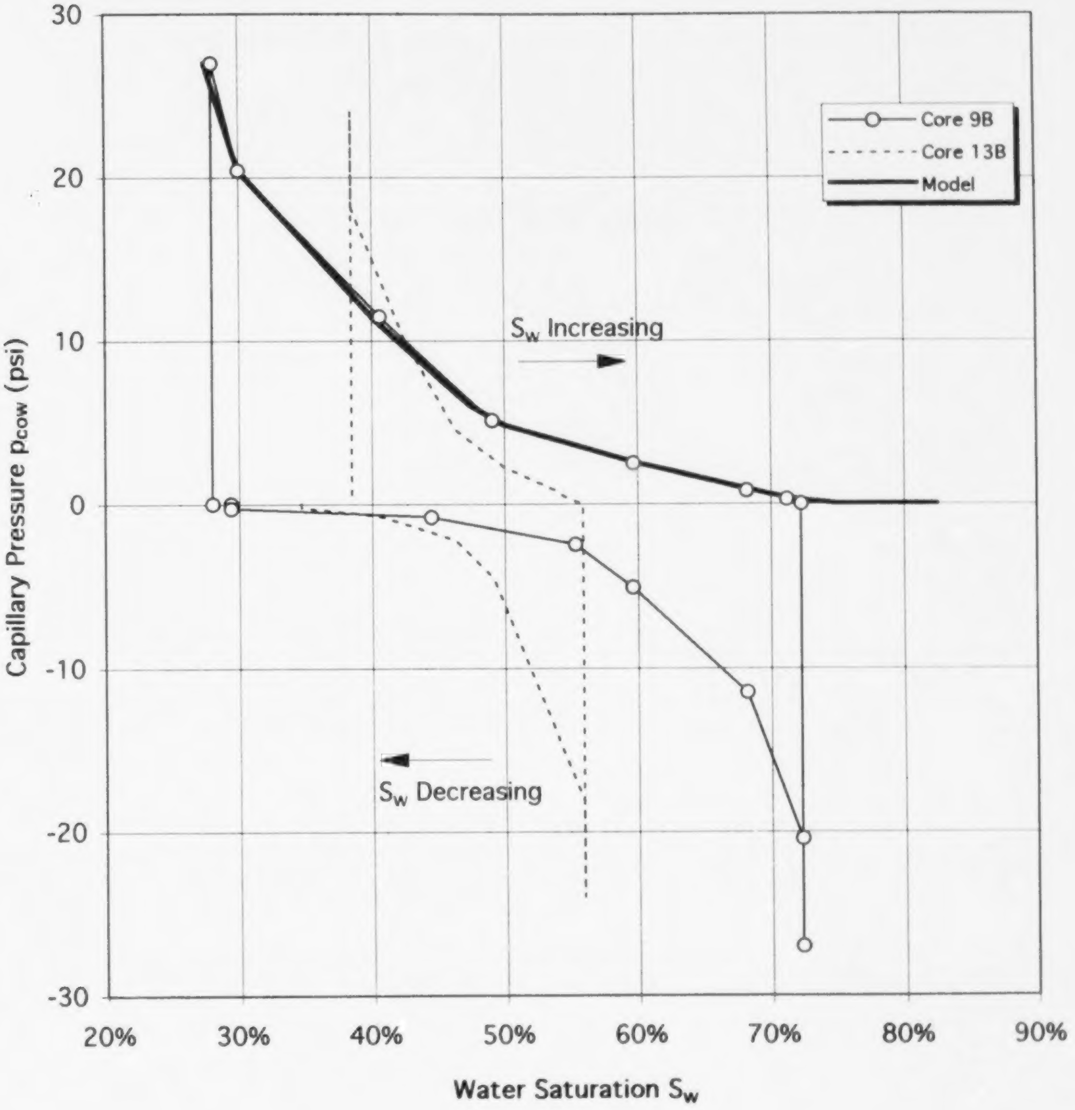

Figure 2.21: Oil-Water Capillary Pressure p_{cow}
(08-17-37-7W5)

2.11 Relative Permeability Data

The phase flow rate under a pressure gradient depends on the absolute rock permeability to fluid flow, the phase viscosity and the relative permeability of that particular phase. When the local reservoir pressure is above the bubble point, undersaturated oil will expand as it moves towards regions of lower pressure. When the pressure drops below the bubble point, dissolved gas will be released from the saturated oil as free gas. This highly compressible free gas will displace oil as it expands locally. As the pressure continues to drop, the evolution of free gas will saturate the surrounding porous media and become mobile as it accumulates to some critical level. Above this critical level, free gas will no longer be trapped locally and will move towards producing wells in its free and mobile state. The producing gas-oil ratio will increase as the mobile free gas flows to the surface along with the solution gas in oil. As the reservoir gas saturation increases, its relative mobility will increase and flow preferentially by impeding the flow of oil. Gas production will increase and oil production decrease, until the rate of free gas evolution drops below the rate of gas production.

Under waterflood pressure, injected water would start to expand and flow towards producing wells. An oil bank would form as it gets compressed ahead of the water front. The piston-like displacement efficiency would depend on the mobility ratio between water and oil (Willhite, 1990, p87-89). The producing oil rate would initially increase and remain relatively constant until the water front advances to the producing wells. As the reservoir water saturation increases, its relative mobility will increase and flow preferentially by impeding the flow of oil. Subsequent production after water breakthrough will have increasing water-oil ratios.

Phase mobilities are directly proportional to phase relative permeabilites and inversely proportional to phase viscosities. Three-phase relative permeabilities are difficult to measure and are typically calculated using two-phase oil-gas and oil-water data. Two-phase relative permeability data was obtained from Canadian Hunter Chedderville Waterflood Design Study (1993). Table 2.13 shows the analysis conducted on two core stacks, #1 and #2, sampled from 08-17-37-7W5. Stack#1 was selected as the basis for the simulation model because its range of data seemed to be more consistent with the bulk of irreducible water estimates (Section 2.7). The procedure described by Demetre(1993) was followed to calculate three-phase relative permeabilities (k_{ro},k_{rw},k_{rg}).

Core:	Stack #1
Well	08-17-37-7W5
Depth KB (ft)	8535.0
Kx (md)	50.1
Porosity	10.10%

Sw	Krw	Kro	Sg	Krg	Krl@Sw=.467
39.90%	0.00000	0.30140	0.00%	0.00000	0.25090
42.00%	0.00006	0.26600	0.60%	0.00092	0.21570
44.20%	0.00025	0.23330	1.20%	0.00191	0.18390
46.30%	0.00061	0.20300	1.90%	0.00292	0.15540
48.40%	0.00120	0.17500	2.50%	0.00395	0.13000
50.50%	0.00205	0.14980	3.10%	0.00500	0.10760
52.70%	0.00320	0.12670	3.70%	0.00605	0.08786
54.80%	0.00469	0.10590	4.30%	0.00711	0.07072
56.90%	0.00653	0.08727	5.00%	0.00818	0.05598
59.00%	0.00875	0.07073	5.60%	0.00926	0.04344
61.20%	0.01140	0.05620	6.20%	0.01034	0.03295
63.30%	0.01447	0.04362	6.80%	0.01143	0.02430
65.40%	0.01801	0.03288	7.40%	0.01252	0.01734
67.50%	0.02204	0.02390	8.10%	0.01362	0.01186
69.70%	0.02657	0.01657	8.70%	0.01472	0.00770
71.80%	0.03162	0.01078	9.30%	0.01582	0.00467
73.90%	0.03723	0.00641	9.90%	0.01693	0.00258
76.00%	0.04340	0.00332	10.50%	0.01804	0.00126
78.20%	0.05015	0.00136	11.20%	0.01916	0.00051
80.30%	0.05752	0.00034	11.80%	0.02028	0.00016
82.40%	0.06550	0.00000	12.40%	0.02140	0.00000

Core:	Stack #2
Well	08-17-37-7W5
Depth KB (ft)	8528.9
Kx (md)	1.47
Porosity	7.10%

Sw	Krw	Kro	Sg	Krg	Krl@Sw=.608
52.8%	0.00000	0.15370	0.0%	0.00000	0.12520
54.1%	0.00359	0.13630	0.6%	0.00071	0.11880
55.3%	0.00748	0.12020	1.1%	0.00148	0.11230
56.6%	0.01149	0.10520	1.7%	0.00228	0.10590
57.9%	0.01558	0.09129	2.2%	0.00309	0.09950
59.2%	0.01973	0.07854	2.8%	0.00391	0.09310
60.4%	0.02394	0.06688	3.3%	0.00475	0.08672
61.7%	0.02818	0.05629	3.9%	0.00559	0.08035
63.0%	0.03246	0.04673	4.4%	0.00644	0.07399
64.2%	0.03678	0.03818	5.0%	0.00730	0.06765
65.5%	0.04112	0.03610	5.6%	0.00816	0.06132
66.8%	0.04549	0.02399	6.1%	0.00902	0.05502
68.0%	0.04988	0.01828	6.7%	0.00990	0.04874
69.3%	0.05430	0.01344	7.2%	0.01077	0.04247
70.6%	0.05873	0.00944	7.8%	0.01165	0.03624
71.9%	0.06319	0.00624	8.3%	0.01253	0.03004
73.1%	0.06766	0.00377	8.9%	0.01342	0.02387
74.4%	0.07215	0.00199	9.4%	0.01431	0.01775
75.7%	0.07665	0.00083	10.0%	0.01520	0.01169
76.9%	0.08117	0.00021	10.5%	0.01610	0.00573
78.2%	0.08570	0.00000	11.1%	0.01700	0.00000

Canadian Hunter Chedderville Waterflood Design Study,
Hycal Energy Research Laboratories Ltd., Calgary, Oct 25, 1993.

Table 2.13: Core Two-Phase Relative Permeabilities

Three-phase relative permeabilities[6] are assumed to have a functional dependence on (S_o, S_w, S_g) as proposed in the probability models of Stone (1970, 1973).

$$k_{ro}=k_{ro}(S_w,S_g) \quad , \quad k_{rw}=k_{rw}(S_w) \quad , \quad k_{rg}=k_{rg}(S_g) \tag{2.8}$$

Two-phase relative permeability functions of water and gas saturations (Coats(1980), Aziz *et al.* (1987)) were used to fit laboratory data:

$$k_{rw}=k_{rwro}\left[\frac{S_w-S_{wir}}{1-S_{orw}-S_{wir}}\right]^{n_w} \qquad k_{rg}=k_{rgro}\left[\frac{S_g-S_{gc}}{1-S_{wir}-S_{org}-S_{gc}}\right]^{n_g}$$

$$k_{row}=k_{roiw}\left[\frac{1-S_{orw}-S_w}{1-S_{orw}-S_{wir}}\right]^{n_{ow}} \qquad k_{rog}=k_{roiw}\left[\frac{1-S_{wir}-S_{org}-S_g}{1-S_{wir}-S_{org}}\right]^{n_{og}} \tag{2.9}$$

S_w	water saturation	S_g	gas saturation
k_{rw}	water relative permeability	k_{rg}	gas relative permeability
k_{row}	oil relative permeability in water-oil	k_{rog}	oil relative permeability in gas-oil
S_{wir}	irreducible connate water saturation	S_{gc}	critical mobile gas saturation
S_{orw}	residual oil saturation in water-oil	S_{org}	residual oil saturation in gas-oil
k_{roiw}	oil relative permeability in water-oil at irreducible water saturation		
k_{rwro}	water relative permeability in water-oil at residual oil saturation	k_{rgro}	gas relative permeability in gas-oil at residual oil saturation
n_w	saturation exponent for k_{rw}	n_g	saturation exponent for k_{rg}
n_{ow}	saturation exponent for k_{row}	n_{og}	saturation exponent for k_{rog}

Table 2.14: Three-Phase Relative Permeability Nomenclature

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[6] Honarpour *et al.* (1986) provide a comprehensive discussion on relative permeability.

Three-phase oil relative permeability k_{ro} in the water-gas-oil system was then calculated using the model proposed by Aziz and Settari (1979) :

$$k_{ro}(S_w,S_g)=k_{roiw}S_o^*\beta_w\beta_g \tag{2.10}$$

where,

$$\begin{array}{lll}
\beta_g=\dfrac{1}{k_{roiw}(1-S_g^*)}k_{rog}(S_l) & \beta_w=\dfrac{1}{k_{roiw}(1-S_w^*)}k_{row}(S_w) & \\
S_l=1-S_g & S_o^*=\dfrac{S_o-S_{orw}}{(1-S_{wir}-S_{orw})} & S_o\geq S_{orw} \\
S_g^*=\dfrac{S_g}{(1-S_{wir}-S_{org})} & S_w^*=\dfrac{S_w-S_{wir}}{(1-S_{wir}-S_{orw})} & S_w\geq S_{wir}
\end{array} \tag{2.11}$$

The two-phase relative permeabilities for stack #1 were fitted using the procedure described above. The results were fine-tuned through the iterative process of history matching. The final results used in the simulation model are given in Table 2.15. A critical gas saturation S_{gc}=2.5% was needed to match gas production history. Two-phase relative permeabilities for the oil-water and oil-gas systems are graphed in Figures 2.22(a) and 2.22(b). Calculated three-phase oil relative permeability is tabulated as a function of S_w and S_g in Table 2.16 and plotted in Figure 2.22(c).

	Irreducible Water		Residual Oil (w)		Residual Oil (g)		Critical Gas
Saturation (Swir) Rel Perm (kroiw)	.2750 .6000	Saturation (Sorw) Rel Perm (krwro)	.1750 .0650	Saturation (Sorg) Rel Perm (krgro)	.2250 .0650	Saturation (Sgc)	.0250

	krw Exponent	krow Exponent			krg Exponent	krog Exponent	
	3.500	2.500			.725	4.000	
Water Saturation (Sw)	Water Relative Permeability (krw)	Oil-Water Relative Permeability (krow)	Oil-Water Capillary Pressure (psi)	Gas Saturation (Sg)	Gas Relative Permeability (krg)	Oil-Gas Relative Permeability (krog)	Gas-Oil Capillary Pressure (psi)
0.0%	.0000	1.0000	.000	0.0%	.0000	.6000	.000
2.5%	.0000	.9636	.000	2.5%	.0000	.4887	.000
5.0%	.0000	.9273	.000	5.0%	.0077	.3937	.000
7.5%	.0000	.8909	.000	7.5%	.0127	.3132	.000
10.0%	.0000	.8545	.000	10.0%	.0171	.2458	.000
12.5%	.0000	.8182	.000	12.5%	.0210	.1898	.000
15.0%	.0000	.7818	.000	15.0%	.0247	.1441	.000
17.5%	.0000	.7455	.000	17.5%	.0282	.1071	.000
20.0%	.0000	.7091	.000	20.0%	.0315	.0778	.000
22.5%	.0000	.6727	.000	22.5%	.0347	.0549	.000
25.0%	.0000	.6364	50.000	25.0%	.0378	.0375	.000
27.5%	.0000	.6000	27.000	27.5%	.0408	.0246	.000
30.0%	.0000	.5341	20.410	30.0%	.0437	.0154	.000
32.5%	.0000	.4728	18.180	32.5%	.0466	.0090	.000
35.0%	.0001	.4159	15.950	35.0%	.0494	.0049	.000
37.5%	.0002	.3633	13.710	37.5%	.0521	.0023	.000
40.0%	.0004	.3149	11.480	40.0%	.0548	.0010	.000
42.5%	.0007	.2706	9.660	42.5%	.0574	.0003	.000
45.0%	.0012	.2303	7.840	45.0%	.0600	.0001	.000
47.5%	.0019	.1938	6.020	47.5%	.0625	.0000	.000
50.0%	.0028	.1610	4.820	50.0%	.0650	.0000	.000
52.5%	.0041	.1318	4.240	52.5%	.1117	.0000	.000
55.0%	.0057	.1061	3.660	55.0%	.1585	.0000	.000
57.5%	.0078	.0836	3.080	57.5%	.2052	.0000	.000
60.0%	.0103	.0642	2.500	60.0%	.2520	.0000	.000
62.5%	.0134	.0478	2.020	62.5%	.2987	.0000	.000
65.0%	.0170	.0343	1.530	65.0%	.3455	.0000	.000
67.5%	.0213	.0233	1.050	67.5%	.3923	.0000	.000
70.0%	.0264	.0148	.550	70.0%	.4390	.0000	.000
72.5%	.0322	.0085	.200	72.5%	.4858	.0000	.000
75.0%	.0389	.0041	.010	75.0%	.5325	.0000	.000
77.5%	.0466	.0015	.000	77.5%	.5792	.0000	.000
80.0%	.0552	.0003	.000	80.0%	.6260	.0000	.000
82.5%	.0650	.0000	.000	82.5%	.6727	.0000	.000
85.0%	.1986	.0000	.000	85.0%	.7195	.0000	.000
87.5%	.3321	.0000	.000	87.5%	.7663	.0000	.000
90.0%	.4657	.0000	.000	90.0%	.8130	.0000	.000
92.5%	.5993	.0000	.000	92.5%	.8598	.0000	.000
95.0%	.7329	.0000	.000	95.0%	.9065	.0000	.000
97.5%	.8664	.0000	.000	97.5%	.9533	.0000	.000
100.0%	1.0000	.0000	.000	100.0%	1.0000	.0000	.000

Table 2.15: Model Two-Phase Relative Permeabilities and Capillary Pressures

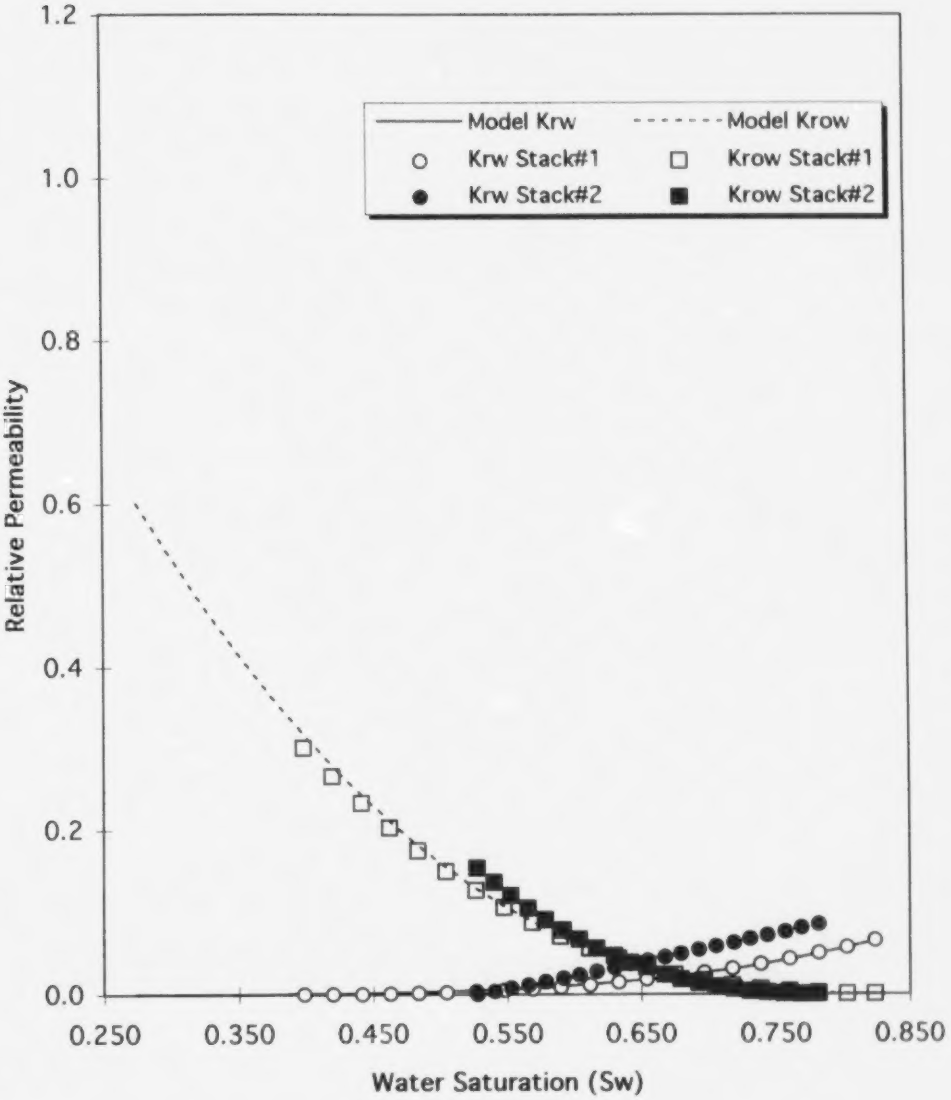

Figure 2.22(a): 2-Phase Water and Water-Oil Relative Permeabilities

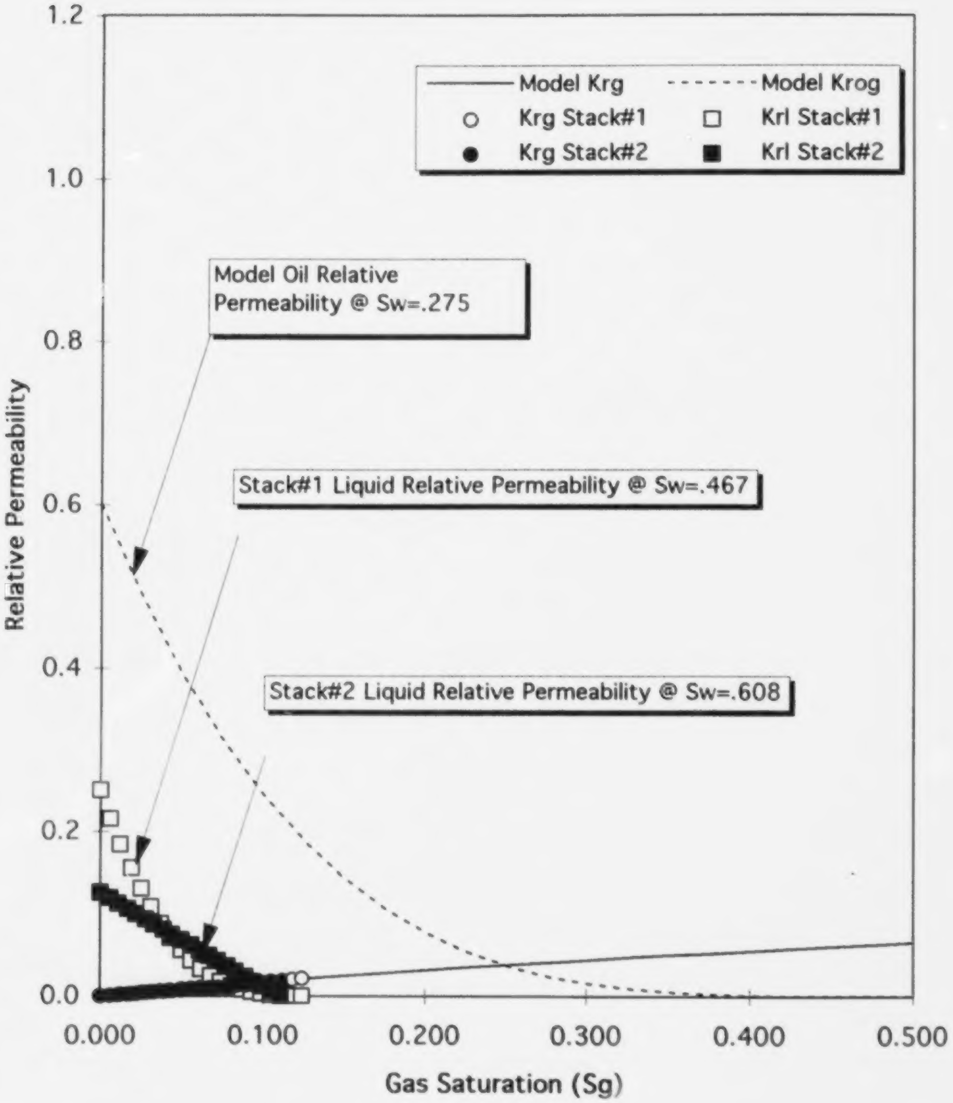

Figure 2.22(b): 2-Phase Gas and Gas-Oil Relative Permeabilities

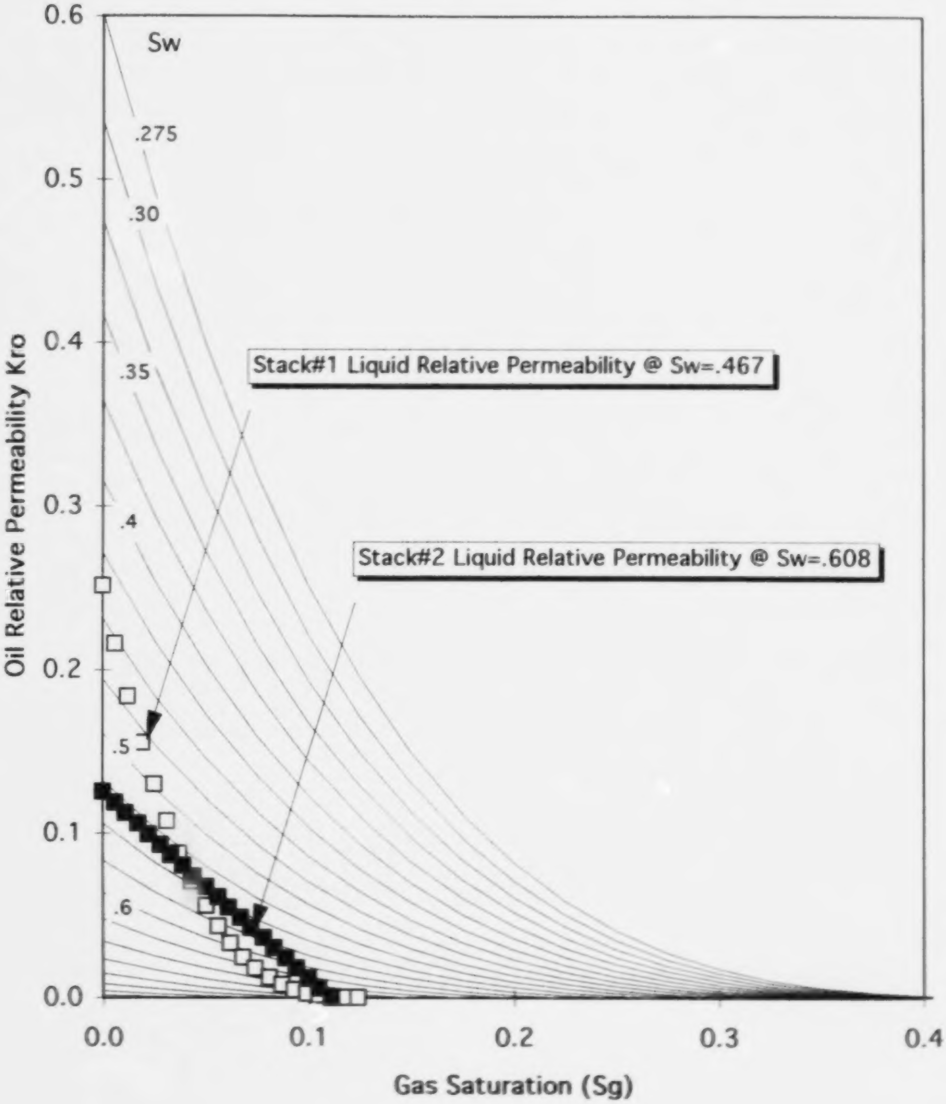

Figure 2.22(c): Model 3-Phase Oil Relative Permeabilities

Sw\Sg	.000	.025	.050	.075	.100	.125	.150	.175	.200	.225	.250	.275	.300	.325	.350	.375	.400	.425	.450	.475	.500
0.275	.600	.491	.398	.318	.251	.196	.150	.112	.082	.059	.041	.027	.017	.011	.006	.003	.001	.000	.000	.000	
0.300	.534	.436	.352	.281	.221	.172	.131	.098	.071	.051	.035	.023	.015	.009	.005	.002	.001	.000	.000	.000	
0.325	.473	.385	.310	.247	.194	.150	.114	.084	.061	.043	.030	.019	.012	.007	.004	.002	.001	.000	.000	.000	
0.350	.416	.338	.271	.215	.168	.129	.098	.072	.052	.036	.025	.016	.010	.006	.003	.001	.001	.000	.000	.000	
0.375	.363	.294	.235	.186	.145	.111	.083	.061	.044	.030	.020	.013	.008	.004	.002	.001	.000	.000	.000	.000	
0.400	.315	.254	.203	.159	.123	.094	.070	.051	.036	.025	.016	.010	.006	.003	.002	.001	.000	.000	.000	.000	
0.425	.271	.218	.173	.135	.104	.078	.058	.042	.029	.020	.013	.008	.004	.002	.001	.000	.000	.000	.000	.000	
0.450	.230	.184	.146	.113	.086	.065	.047	.034	.023	.015	.010	.006	.003	.001	.000	.000	.000	.000	.000	.000	
0.475	.194	.154	.121	.094	.071	.053	.038	.027	.018	.012	.007	.004	.002	.001	.000	.000	.000	.000	.000	.000	
0.500	.161	.127	.099	.076	.057	.042	.030	.020	.013	.008	.005	.002	.001	.000	.000	.000	.000	.000	.000	.000	
0.525	.132	.104	.080	.061	.045	.032	.023	.015	.009	.005	.003	.001	.000	.000	.000	.000	.000	.000	.000	.000	
0.550	.106	.083	.063	.047	.035	.024	.017	.011	.006	.003	.001	.000	.000	.000	.000	.000	.000	.000	.000		
0.575	.084	.064	.049	.036	.026	.018	.011	.007	.004	.001	.000	.000	.000	.000	.000	.000	.000	.000			
0.600	.064	.049	.036	.026	.018	.012	.007	.004	.002	.000	.000	.000	.000	.000	.000	.000					
0.625	.048	.036	.026	.018	.012	.008	.004	.002	.000	.000	.000	.000	.000	.000	.000	.000					
0.650	.034	.025	.018	.012	.008	.004	.002	.000	.000	.000	.000	.000	.000	.000	.000						
0.675	.023	.017	.011	.007	.004	.002	.000	.000	.000	.000	.000	.000	.000	.000							
0.700	.015	.010	.006	.004	.002	.000	.000	.000	.000	.000	.000	.000	.000								
0.725	.008	.005	.003	.001	.000	.000	.000	.000	.000	.000	.000										
0.750	.004	.002	.001	.000	.000	.000	.000	.000	.000	.000	.000										
0.775	.001	.001	.000	.000	.000	.000	.000	.000	.000	.000											
0.800	.000	.000	.000	.000	.000	.000	.000	.000													
0.825	.000	.000	.000	.000	.000	.000	.000	.000													

Table 2.16: Model Three-Phase Oil Relative Permeability K_{ro}

2.12 Initial Depletion State

The reservoir depletion state is sufficiently described by the distributions of (p, S_w, S_g). The initial reservoir pressure state (1-Nov-87) was deduced from the current bottomhole pressure history (1-Oct-94) listed in Table 2.17. Pressure data from a bottomhole pool summary (ERCB) was sparse and scattered in both space and time. The data represented various states of depletion over seven years of production. Fourteen wells had been initiated at different times. The initialization procedure was based on the premise that the reservoir flow was originally at equilibrium (Franchi *et al.* 1982). Phase potential differences due to gravitational terms were assumed to be in balance and that no fluid migration was occurring under gravity-capillary equilibrium conditions. A reference pressure was estimated at an arbitrary depth (5300 feet subsea) selected below the deepest point in the reservoir southwest corner. There was no identifiable water-oil contact at this depth. The bulk of the reservoir was assumed to be initially undersaturated, with some upper portion saturated at a critical gas level. An initial bubble point pressure distribution was estimated. An undersaturated oil density distribution was calculated at the fixed reference pressure using estimated bubble point pressures. The calculated oil density reflected only the variation in bubble point with no variation[7] in actual pressure. A static head distribution was determined with respect to the reference depth using approximate densities. An equilibrium pressure distribution was then assigned to each grid block as the reference pressure offset by the local static head. The reference pressure was adjusted manually until an acceptable distribution was found to locally match early historical data at designated grid blocks. The reference pressure was initialized to 3350 psia. The initial pressure distribution is tabulated in Table 2.18(a) and plotted in Figure 2.23(a).

$$p^0_{ijk} = p_{ref} + \frac{1}{B_o}(\rho_{sco} + R_{so}\rho_{scg})(z_{ijk} - z_{ref})g \tag{2.12}$$

The initial water saturation was assumed to be at the irreducible state (Table 2.6(e), Figure 2.17(e)). The initial gas saturation state was deduced by matching historical production data (Chapter 4). The first two wells in chronological producing order, 16-09-37-7W5 and 06-15-37-7W5, exhibited historical gas-oil ratios characteristic of saturated bottomhole conditions from the start. Gas production from these wells were much higher than that expected from dissovled gas alone. This fact suggested that a local free gas saturation was initially present. Producing gas-oil ratios for other wells were observed to cross over, from undersaturated to saturated behaviour, sequentially down the east-west dip of the pool. The bubble point pressure determines the local vapour-liquid ratio between free gas and oil saturations. The initial bubble point pressure and the free gas saturation were both manually fit to match the oil and gas production data. A developing gas cap was assumed to be initially saturated at critical gas levels to maintain vertical pressure equilibrium. Initial gas cap boundaries were interpolated through trial and error to match the sequential crossovers observed in historical gas-oil ratios. The initial distributions for oil saturation, gas saturation and local bubble point pressure are tabulated in Tables 2.18(b)-(d) and plotted in Figures 2.23(b)-(d).

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[7] This approximation linearized the equation.

The matched bubble point distribution in Figure 2.23(d) indicates some disturbance in the center of the pool. Large temperature variations were also observed in historical log data. New information obtained after history match shed some light on this anomalous behaviour. There was evidence of pressure communication between the Viking "A" pool and a lower Mannville formation at a single well (14-09-37W5) located at the source of the disturbance. This well had apparently been producing from the lower formation for a number of years before it started producing from Viking "A". In fact, (14-09-37W5) was producing from the Mannville formation for about a year before the first well (16-09-37W5) started in Viking "A". Production from the Mannville zone was at extremely high initial gas rates, an order of magnitude larger than that observed in Viking "A". Production from the Mannville zone was shut in shortly after (14-09-37W5) started producing from Viking "A". The initial bubble point disturbance observed for Viking "A" was rationalized as a high pressure gas influx through the connecting hole from the zone below. The sustained high pressure gas source could potentially account for an up-dip gas migration in Viking "A" to form a gas cap, and a down-dip nonisothermal solution gas migration to lighten the crude oil. Lighter oils would be characterized by the higher bubble point pressures observed in the wake of migration.

The initial depletion state defined in this section is therefore not the true initial state, but a representative state that accounts for the cumulative effect of pressure communication with the lower formation.

	16-09-37-7W5
Date	Pressure (psia)
16-Nov-87	2506

	06-15-37-7W5
Date	Pressure (psia)
20-Feb-89	3024
14-Jul-89	2539
4-Jan-90	1922
23-Mar-90	2914
27-Jun-91	2789

	8-13-37-8W5
Date	Pressure (psia)
22-Mar-90	3154
25-Apr-90	3139
15-Jan-91	3098
10-Dec-91	2998
16-Mar-92	2904
19-Jan-93	2861

	6-13-37-8W5
Date	Pressure (psia)
29-Jan-91	3058

	06-16-37-7W5
Date	Pressure (psia)
7-Oct-90	3135
16-Apr-92	2957
19-Oct-92	2906
19-Jan-93	2911

	8-14-37-8W5
Date	Pressure (psia)
29-Sep-94	2550

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	08-18-37-7W5
Date	Pressure (psia)
14-Mar-92	2591
23-Apr-92	2982
12-Sep-92	2932

	16-08-37-7W5
Date	Pressure (psia)
3-Apr-93	2748

	14-09-37-7W5
Date	Pressure (psia)
27-Jan-93	2739

	08-17-37-7W5
Date	Pressure (psia)
2-Apr-93	2901

	14-07-37-7W5
Date	Pressure (psia)
27-Jul-93	2819

	14-12-37-8W5
Date	Pressure (psia)
8-Nov-94	2528

	16-12-37-8W5
Date	Pressure (psia)
10-Dec-93	2704
26-Jan-94	2663

	08-07-37-7W5
Date	Pressure (psia)
13-May-94	2627
6-Jun-94	2615

Table 2.17: Chedderville Viking "A" Pressure History (1-Oct-94)

k = 1	Po-Equilibrium Pressure (psia)																																																				
N	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
1																																																						
2																																																						
3										3320																																												
4									3323	3321	3318																																											
5								3327	3324	3321	3318	3315																																										
6							3331	3328	3325	3322	3318	3314	3311																																									
7						3334	3332	3330	3326	3322	3317	3313	3309	3307																																								
8					3335	3335	3334	3332	3328	3322	3316	3311	3308	3305	3303																																							
9				3335	3335	3335	3335	3335	3328	3322	3315	3309	3307	3304	3302	3300																																						
10			3335	3335	3335	3335	3334	3331	3327	3321	3315	3310	3307	3304	3302	3300	3298																																					
11		3335	3335	3335	3334	3333	3331	3329	3325	3320	3315	3310	3307	3304	3302	3299	3297	3295																																				
12	3334	3334	3335	3335	3333	3332	3329	3326	3323	3318	3314	3310	3307	3305	3302	3300	3297	3294	3291																																			
13	3333	3333	3334	3334	3332	3330	3327	3324	3321	3317	3314	3310	3307	3305	3303	3300	3297	3294	3291	3287	3286	3284	3282	3280	3277	3275	3273	3271	3264	3257	3251	3244	3244	3244	3245	3244	3245	3245	3246	3245	3244	3243	3241	3240	3239	3237	3236							
14	3332	3332	3332	3332	3330	3328	3326	3323	3320	3317	3314	3311	3308	3306	3304	3301	3298	3295	3291	3288	3286	3283	3281	3279	3277	3274	3272	3268	3263	3257	3250	3246	3244	3243	3243	3243	3243	3243	3244	3243	3242	3241	3240	3238	3237	3236	3234	3233						
15	3330	3331	3330	3330	3329	3327	3324	3322	3319	3316	3314	3311	3309	3307	3305	3302	3299	3296	3292	3289	3286	3283	3281	3278	3276	3273	3270	3266	3261	3256	3251	3247	3245	3243	3243	3242	3242	3242	3242	3241	3240	3239	3238	3237	3235	3234	3232	3230						
16	3329	3329	3329	3328	3327	3325	3323	3321	3319	3316	3314	3312	3310	3308	3306	3304	3301	3297	3293	3290	3286	3283	3281	3278	3275	3272	3269	3265	3260	3256	3252	3248	3245	3244	3243	3242	3241	3241	3241	3240	3239	3238	3236	3235	3233	3232	3230	3228						
17																																3249	3246	3244	3243	3242	3241	3240	3240	3239	3238	3236	3235	3233	3232	3230	3228	3226						
18																																					3241	3240	3239	3238	3236	3235	3234	3232	3230	3229	3227							

k = 2	Po-Equilibrium Pressure (psia)																																																				
N	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
1												3316	3314	3312	3310	3308	3306	3305	3303	3301	3299	3298	3296																															
2											3319	3317	3314	3312	3310	3308	3306	3305	3303	3301	3299	3298	3296	3294																														
3										3322	3320	3317	3315	3313	3311	3309	3307	3305	3303	3301	3299	3298	3296	3294	3293																													
4									3326	3323	3321	3318	3315	3313	3311	3309	3306	3305	3303	3301	3299	3297	3296	3294	3292	3291																												
5								3329	3327	3324	3321	3318	3315	3313	3310	3308	3306	3304	3302	3301	3299	3297	3295	3293	3292	3290	3288																											
6							3334	3332	3329	3326	3322	3318	3315	3312	3310	3308	3306	3304	3302	3300	3298	3296	3295	3293	3291	3289	3287	3284	3281	3277	3274	3271	3269	3267	3265	3263	3262																	
7						3338	3337	3335	3331	3326	3322	3318	3314	3311	3309	3307	3305	3303	3301	3300	3298	3296	3294	3292	3290	3287	3284	3281	3278	3275	3272	3269	3267	3265	3264	3262	3261	3259	3257	3255	3253	3252	3250											
8					3340	3340	3339	3337	3332	3327	3321	3315	3312	3310	3308	3306	3304	3302	3301	3299	3297	3295	3293	3291	3288	3285	3282	3279	3275	3272	3269	3266	3264	3263	3262	3261	3259	3258	3256	3254	3252	3251	3249	3248	3246	3244	3243	3241	3240					
9				3340	3340	3340	3339	3338	3332	3326	3319	3312	3310	3308	3306	3304	3302	3301	3299	3297	3295	3293	3291	3289	3286	3283	3280	3276	3273	3270	3266	3263	3261	3260	3260	3260	3258	3256	3254	3253	3251	3250	3248	3247	3245	3244	3242	3240	3239	3237				
10			3339	3339	3339	3339	3337	3335	3330	3324	3318	3313	3310	3307	3305	3303	3301	3299	3297	3295	3293	3291	3289	3287	3284	3281	3278	3274	3271	3267	3263	3260	3258	3257	3257	3256	3255	3254	3253	3251	3250	3248	3247	3246	3244	3243	3241	3239	3238	3236	3234			
11		3338	3338	3338	3338	3336	3334	3332	3327	3322	3317	3313	3309	3307	3304	3302	3300	3298	3295	3293	3291	3289	3287	3285	3282	3280	3277	3273	3269	3264	3259	3256	3254	3253	3253	3253	3253	3252	3251	3250	3249	3247	3246	3245	3243	3242	3240	3239	3237	3234	3232	3230		
12	3336	3337	3337	3337	3336	3334	3331	3328	3325	3321	3316	3312	3309	3307	3304	3302	3299	3296	3294	3291	3289	3287	3285	3283	3281	3278	3276	3272	3267	3261	3255	3251	3249	3249	3250	3250	3250	3250	3249	3248	3247	3246	3245	3243	3242	3241	3239	3238	3236	3233	3231	3229	3227	
13	3335	3335	3335	3335	3334	3332	3329	3325	3322	3319	3315	3311	3309	3307	3304	3302	3299	3296	3292	3289	3287	3285	3283	3281	3279	3277	3274	3272	3266	3259	3252	3246	3246	3246	3246	3246	3247	3247	3247	3247	3246	3245	3243	3242	3241	3239	3238	3237	3234	3232	3229	3227	3225	3223
14	3333	3333	3333	3333	3331	3329	3327	3324	3321	3318	3315	3312	3309	3307	3305	3302	3299	3296	3292	3289	3287	3284	3282	3280	3278	3275	3273	3269	3264	3258	3252	3247	3245	3245	3245	3245	3245	3245	3245	3245	3244	3243	3241	3240	3239	3237	3236	3234	3232	3230	3227	3225	3223	3221
15	3331	3331	3331	3330	3329	3327	3325	3322	3320	3317	3314	3312	3310	3307	3305	3303	3300	3296	3293	3289	3287	3284	3281	3279	3276	3273	3270	3267	3262	3257	3252	3248	3246	3244	3244	3243	3243	3243	3243	3243	3242	3241	3239	3238	3237	3235	3234	3232	3230	3227	3225	3223	3221	3219
16	3329	3329	3329	3328	3327	3325	3323	3321	3319	3316	3314	3312	3310	3308	3306	3304	3301	3297	3293	3290	3286	3284	3281	3278	3275	3272	3269	3265	3261	3256	3252	3248	3246	3244	3243	3243	3242	3242	3242	3241	3240	3239	3237	3236	3234	3233	3231	3229	3227	3225	3223	3220	3218	
ct-94)																																3249	3246	3244	3243	3242	3241	3241	3240	3239	3238	3237	3235	3234	3232	3231	3229	3227	3225	3222	3220	3218		
18																																					3240	3240	3239	3238	3236	3235	3233	3232	3230	3228	3227	3225	3222	3220	3218			

Table 2.18(a): Initial Equilibrium Pressure p_o

k = 1	So-Oil Saturation																																																				
N	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
1																																																						
2																																																						
3										.725																																												
4									.725	.725	.725																																											
5								.725	.725	.725	.725	.725																																										
6							.725	.725	.725	.725	.725	.725	.725																																									
7						.725	.725	.725	.725	.725	.725	.725	.725	.725																																								
8					.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725																																							
9				.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725																																						
10			.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725																																					
11		.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725																																				
12	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725																																			
13	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.700	.700	.700	.700	.700	.700	.700	.700	.700							
14	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.700	.700	.700	.700	.700	.700	.700	.700	.700	.700						
15	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.700	.700	.700	.700	.700	.700	.700	.700	.700	.700						
16	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.700	.700	.700	.700	.700	.700	.700	.700	.700	.700						
17																																.725	.725	.725	.725	.725	.725	.725	.700	.700	.700	.700	.700	.700	.700	.700	.700	.700						
18																																					.725	.725	.700	.700	.700	.700	.700	.700	.700	.700	.700							

k = 2	So-Oil Saturation																																																				
N	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
1												.722	.721	.720	.719	.718	.717	.715	.712	.709	.706	.702	.698																															
2											.724	.723	.722	.721	.720	.719	.718	.716	.714	.711	.707	.703	.698	.695																														
3										.725	.725	.724	.723	.722	.721	.720	.719	.718	.716	.713	.709	.703	.698	.695	.692																													
4									.725	.725	.725	.725	.724	.723	.722	.721	.720	.719	.718	.715	.711	.705	.698	.696	.693	.689																												
5								.725	.725	.725	.725	.725	.725	.724	.723	.722	.721	.720	.720	.718	.714	.709	.703	.698	.695	.691	.688																											
6							.725	.725	.725	.725	.725	.725	.725	.725	.724	.723	.722	.721	.721	.720	.718	.714	.709	.703	.698	.695	.691	.688	.684	.673	.658	.641	.627	.627	.602	.602	.602																	
7						.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.724	.723	.722	.721	.721	.720	.718	.714	.709	.704	.698	.695	.692	.688	.684	.671	.656	.640	.627	.602	.602	.602	.602	.602	.602	.602	.602	.602											
8					.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.724	.723	.722	.721	.721	.720	.718	.714	.709	.704	.698	.695	.692	.688	.684	.671	.656	.642	.602	.602	.602	.602	.602	.602	.602	.602	.602	.602	.602	.602	.602	.602	.602					
9				.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.724	.723	.722	.722	.721	.720	.718	.714	.709	.703	.698	.695	.691	.688	.684	.672	.662	.625	.602	.602	.602	.602	.602	.602	.602	.602	.602	.602	.602	.602	.602	.602	.602				
10			.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.724	.723	.723	.722	.721	.720	.718	.714	.709	.704	.698	.694	.691	.689	.684	.684	.659	.659	.659	.659	.659	.659	.659	.659	.659	.659	.659	.659	.659	.602	.602	.602	.602			
11		.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.724	.724	.723	.723	.722	.721	.718	.714	.710	.706	.698	.698	.698	.698	.698	.673	.673	.673	.673	.673	.673	.673	.673	.673	.673	.673	.673	.673	.659	.602	.602	.602	.602		
12	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.724	.724	.723	.722	.718	.718	.718	.718	.718	.718	.718	.718	.718	.693	.693	.693	.693	.693	.693	.693	.693	.693	.693	.693	.693	.673	.659	.602	.602	.602	.602	
13	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.700	.700	.700	.700	.700	.700	.700	.700	.700	.693	.673	.659	.602	.602	.602	.602
14	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.700	.700	.700	.700	.700	.700	.700	.700	.700	.700	.693	.673	.659	.602	.602	.602
15	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.700	.700	.700	.700	.700	.700	.700	.700	.700	.700	.693	.673	.659	.602	.602	.602
16	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.725	.700	.700	.700	.700	.700	.700	.700	.700	.700	.700	.693	.673	.659	.602	.602	
[illegible]																																.725	.725	.725	.725	.725	.725	.725	.700	.700	.700	.700	.700	.700	.700	.700	.700	.700	.693	.673	.659	.602		
18																																					.725	.725	.700	.700	.700	.700	.700	.700	.700	.700	.700	.693	.673	.659	.602			

Table 2.18(b): Initial Oil Saturation S_o

k = 1	Sg-Gas Saturation																																																					
N	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
1																																																						
2																																																						
3																																																						
4																																																						
5																																																						
6																																																						
7																																																						
8																																																						
9																																																						
10																																																						
11																																																						
12																																																						
13																																								.025	.025	.025	.025	.025	.025	.025	.025	.025							
14																																							.025	.025	.025	.025	.025	.025	.025	.025	.025	.025						
15																																							.025	.025	.025	.025	.025	.025	.025	.025	.025	.025						
16																																							.025	.025	.025	.025	.025	.025	.025	.025	.025	.025						
17																																							.025	.025	.025	.025	.025	.025	.025	.025	.025	.025						
18																																							.025	.025	.025	.025	.025	.025	.025	.025	.025							

k = 2	Sg-Gas Saturation																																																					
N	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
1																																																						
2																																																						
3																																																						
4																																																						
5																																																						
6																																			.025	.025	.025																		
7																																			.025	.025	.025	.025	.025	.025	.025	.025	.025											
8																																			.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025					
9																																			.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025				
10																																			.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025			
11																																			.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025		
12																																				.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	
13																																							.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025
14																																							.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025
15																																							.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025
16																																							.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	
ct-94)																																							.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025		
18																																							.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025			

Table 2.18(c): Initial Gas Saturation S_g

k = 1	Bubble Point Pressure (psia)																																																				
N	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
1																																																						
2																																																						
3										2700																																												
4									2700	2700	2725																																											
5								2700	2700	2700	2725	2750																																										
6							2700	2700	2700	2700	2725	2754	2790																																									
7						2700	2700	2700	2700	2700	2723	2757	2805	2862																																								
8					2700	2700	2700	2700	2700	2711	2727	2757	2817	2893	2971																																							
9				2700	2700	2700	2700	2700	2721	2736	2746	2750	2834	2916	3003	3100																																						
10			2725	2725	2725	2725	2725	2745	2766	2784	2798	2820	2868	2929	2992	3043	3060																																					
11		2700	2725	2750	2750	2750	2782	2807	2828	2845	2863	2883	2906	2933	2960	2980	2990	2994																																				
12	2700	2700	2725	2750	2800	2825	2856	2880	2894	2907	2927	2941	2938	2931	2925	2915	2914	2917	2918																																			
13	2700	2700	2725	2750	2850	2900	2925	2950	2950	2950	2975	3000	2950	2925	2900	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2875	2900	2925	2950	2975	3000	3050	3100	3150	3200	3422	3421	3420	3419	3417	3416	3414	3413	3412							
14	2700	2700	2725	2750	2850	2900	2925	2950	2950	2950	2975	3000	2950	2925	2900	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2875	2900	2925	2950	2975	3000	3050	3100	3150	3200	3420	3419	3418	3417	3415	3414	3412	3411	3410	3408						
15	2700	2700	2725	2750	2850	2900	2925	2950	2950	2950	2975	3000	2950	2925	2900	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2875	2900	2925	2950	2975	3000	3050	3100	3150	3200	3418	3417	3416	3415	3414	3412	3411	3409	3407	3406						
16	2700	2700	2725	2750	2850	2900	2925	2950	2950	2950	2975	3000	2950	2925	2900	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2875	2900	2925	2950	2975	3000	3050	3100	3150	3200	3417	3416	3415	3413	3412	3410	3409	3407	3405	3403						
17																																2950	2975	3000	3050	3100	3150	3200	3416	3414	3413	3412	3410	3409	3407	3405	3403	3401						
18																																					3150	3200	3415	3413	3412	3411	3409	3407	3406	3404	3402							

k = 2	Bubble Point Pressure (psia)																																																				
N	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
1												2750	2775	2800	2825	2850	2863	2875	2888	2900	2913	2925	2938																															
2											2725	2750	2775	2800	2825	2850	2863	2875	2888	2900	2913	2925	2938	2950																														
3										2700	2725	2750	2775	2800	2825	2850	2863	2875	2888	2900	2913	2925	2938	2950	2975																													
4									2700	2700	2725	2750	2775	2800	2825	2850	2863	2875	2888	2900	2913	2925	2938	2950	2975	3000																												
5								2700	2700	2700	2725	2750	2775	2800	2825	2850	2863	2875	2888	2900	2913	2925	2938	2950	2975	3000	3025																											
6							2700	2700	2700	2700	2725	2754	2790	2830	2869	2903	2925	2939	2951	2961	2973	2985	2998	3013	3033	3055	3077	3099	3121	3143	3165	3192	3229	3269	3471	3469	3468																	
7						2700	2700	2700	2700	2700	2723	2757	2805	2862	2920	2967	2995	3009	3018	3027	3037	3049	3063	3078	3095	3114	3133	3151	3169	3188	3206	3228	3254	3280	3470	3468	3466	3464	3463	3461	3459	3457	3455											
8					2700	2700	2700	2700	2700	2711	2727	2757	2817	2893	2971	3035	3062	3070	3074	3079	3090	3102	3116	3130	3145	3160	3176	3191	3206	3220	3235	3250	3267	3284	3468	3467	3465	3463	3461	3459	3458	3456	3454	3452	3451	3449	3447	3446	3444					
9				2700	2700	2700	2700	2700	2721	2736	2746	2750	2834	2916	3003	3100	3100	3100	3100	3100	3113	3125	3138	3150	3163	3175	3188	3200	3213	3225	3238	3250	3263	3275	3458	3466	3463	3462	3460	3458	3456	3455	3453	3451	3450	3448	3446	3445	3443	3441				
10			2725	2725	2725	2725	2725	2745	2766	2784	2798	2820	2868	2929	2992	3043	3060	3062	3062	3064	3071	3081	3090	3100	3109	3118	3128	3139	3152	3166	3183	3202	3228	3264	3445	3444	3443	3442	3440	3439	3437	3436	3434	3433	3431	3430	3428	3444	3442	3440	3438			
11		2700	2725	2750	2750	2750	2782	2807	2828	2845	2863	2883	2906	2933	2960	2980	2990	2994	2995	2997	3002	3007	3014	3020	3025	3031	3038	3048	3062	3081	3102	3128	3164	3220	3437	3437	3436	3435	3434	3433	3432	3431	3429	3428	3426	3425	3423	3425	3441	3438	3436	3434		
12	2700	2700	2725	2750	2800	2825	2856	2880	2894	2907	2927	2941	2938	2931	2925	2915	2914	2917	2918	2920	2922	2925	2928	2931	2933	2935	2939	2946	2964	2986	3010	3037	3072	3123	3198	3428	3428	3428	3427	3427	3425	3424	3422	3421	3420	3418	3417	3420	3422	3437	3435	3432	3430	
13	2700	2700	2725	2750	2850	2900	2925	2950	2950	2950	2975	3000	2950	2925	2900	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2875	2900	2925	2950	2975	3000	3050	3100	3150	3200	3424	3423	3422	3421	3419	3418	3416	3415	3414	3415	3417	3418	3433	3430	3428	3426
14	2700	2700	2725	2750	2850	2900	2925	2950	2950	2950	2975	3000	2950	2925	2900	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2875	2900	2925	2950	2975	3000	3050	3100	3150	3200	3421	3421	3420	3419	3417	3416	3414	3413	3412	3410	3409	3412	3413	3428	3426	3424
15	2700	2700	2725	2750	2850	2900	2925	2950	2950	2950	2975	3000	2950	2925	2900	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2875	2900	2925	2950	2975	3000	3050	3100	3150	3200	3419	3419	3418	3416	3415	3414	3412	3411	3409	3407	3406	3409	3411	3426	3424	3422
16	2700	2700	2725	2750	2850	2900	2925	2950	2950	2950	2975	3000	2950	2925	2900	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2875	2900	2925	2950	2975	3000	3050	3100	3150	3200	3418	3417	3416	3414	3413	3411	3410	3408	3406	3404	3404	3407	3408	3423	3421	
k(1.94)																																2950	2975	3000	3050	3100	3150	3200	3416	3415	3414	3412	3411	3409	3408	3406	3404	3402	3401	3404	3406	3421		
18																																					3150	3200	3415	3413	3412	3410	3409	3407	3405	3404	3402	3401	3404	3406	3421			

Table 2.18(d): Initial Bubble Point Pressure p_b

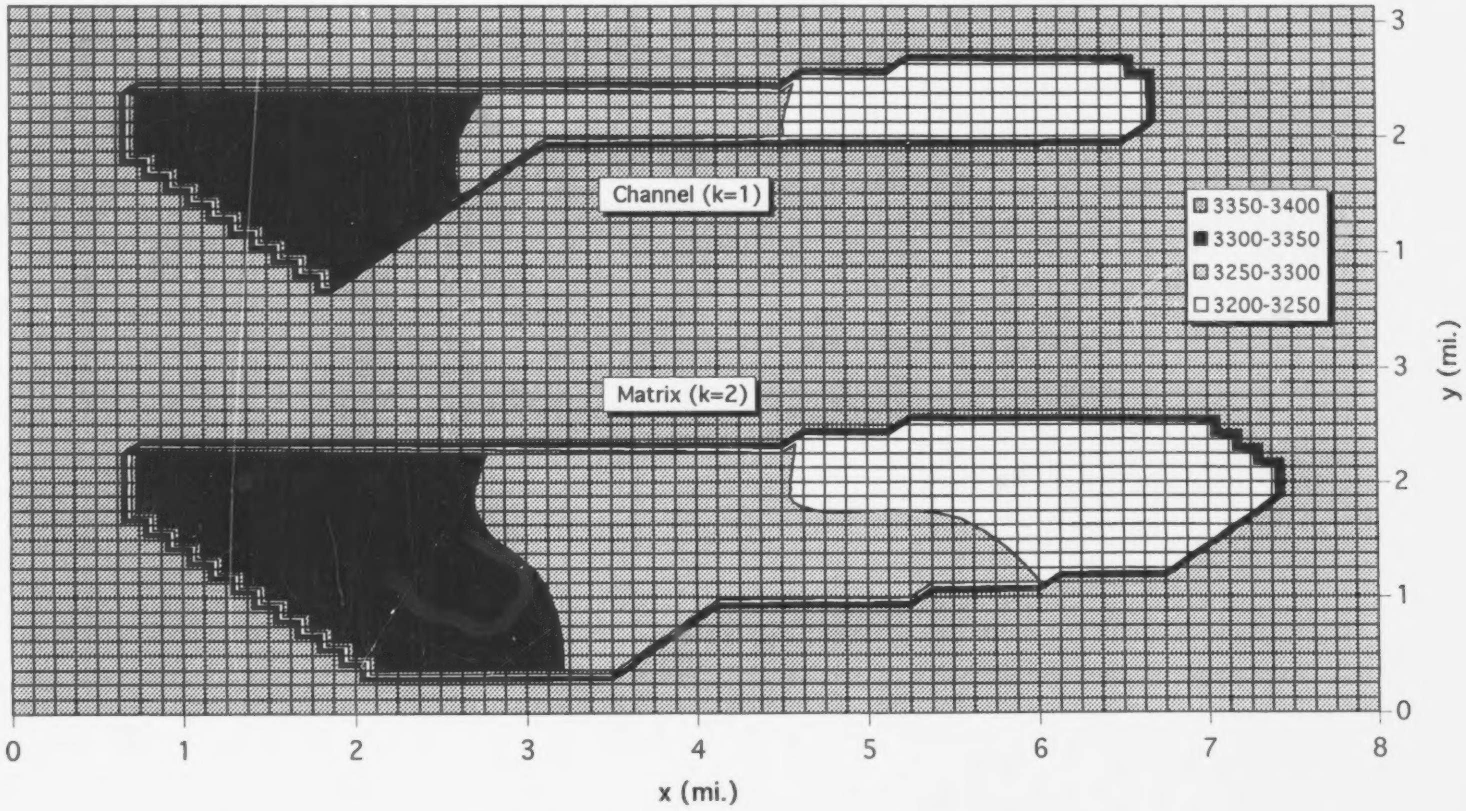

Figure 2.23(a): Initial (Nov-87) Pressure p (psia)

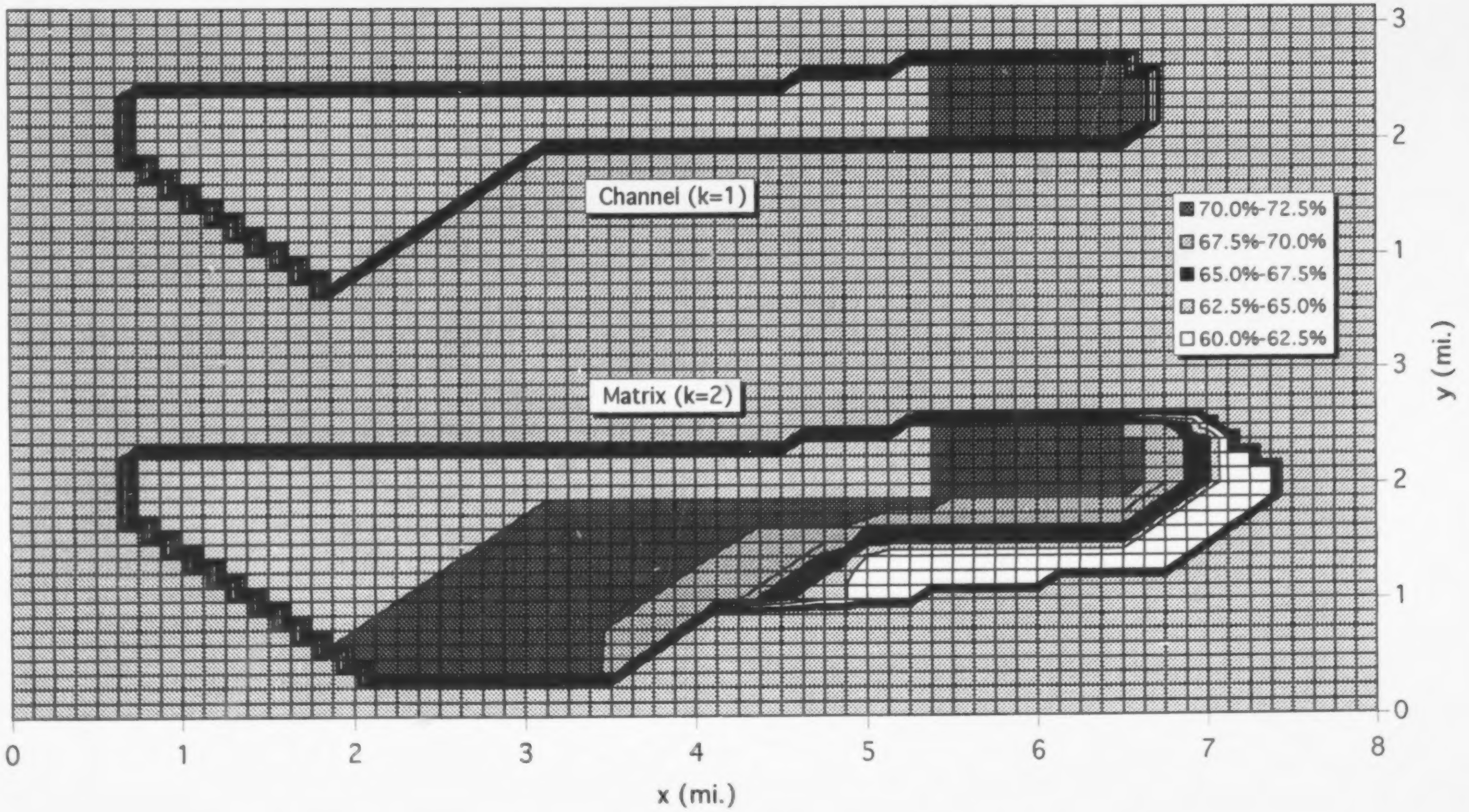

Figure 2.23(b): Initial (Nov-87) Oil Saturation S_o

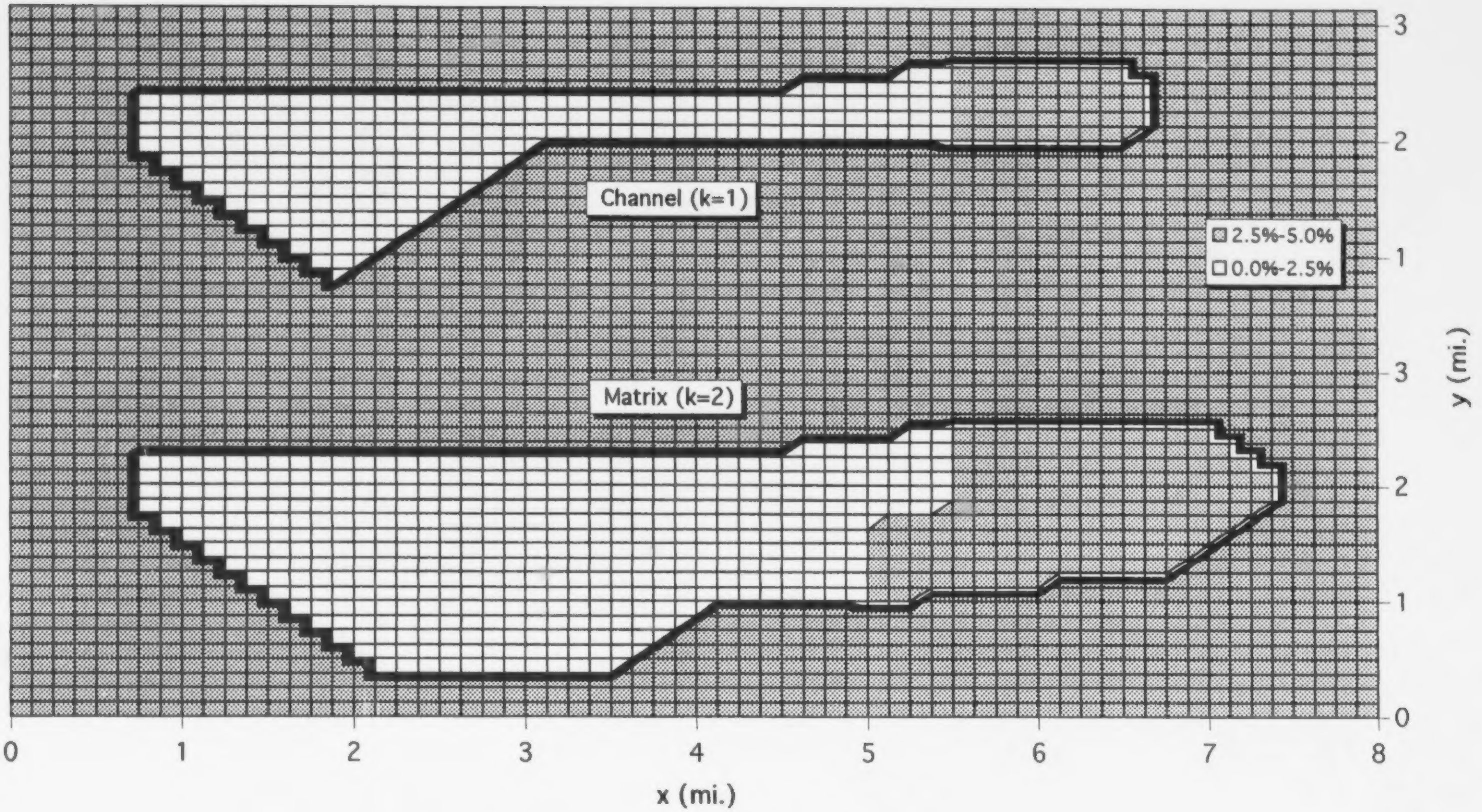

Figure 2.23(c): Initial (Nov-87) Gas Saturation S_g

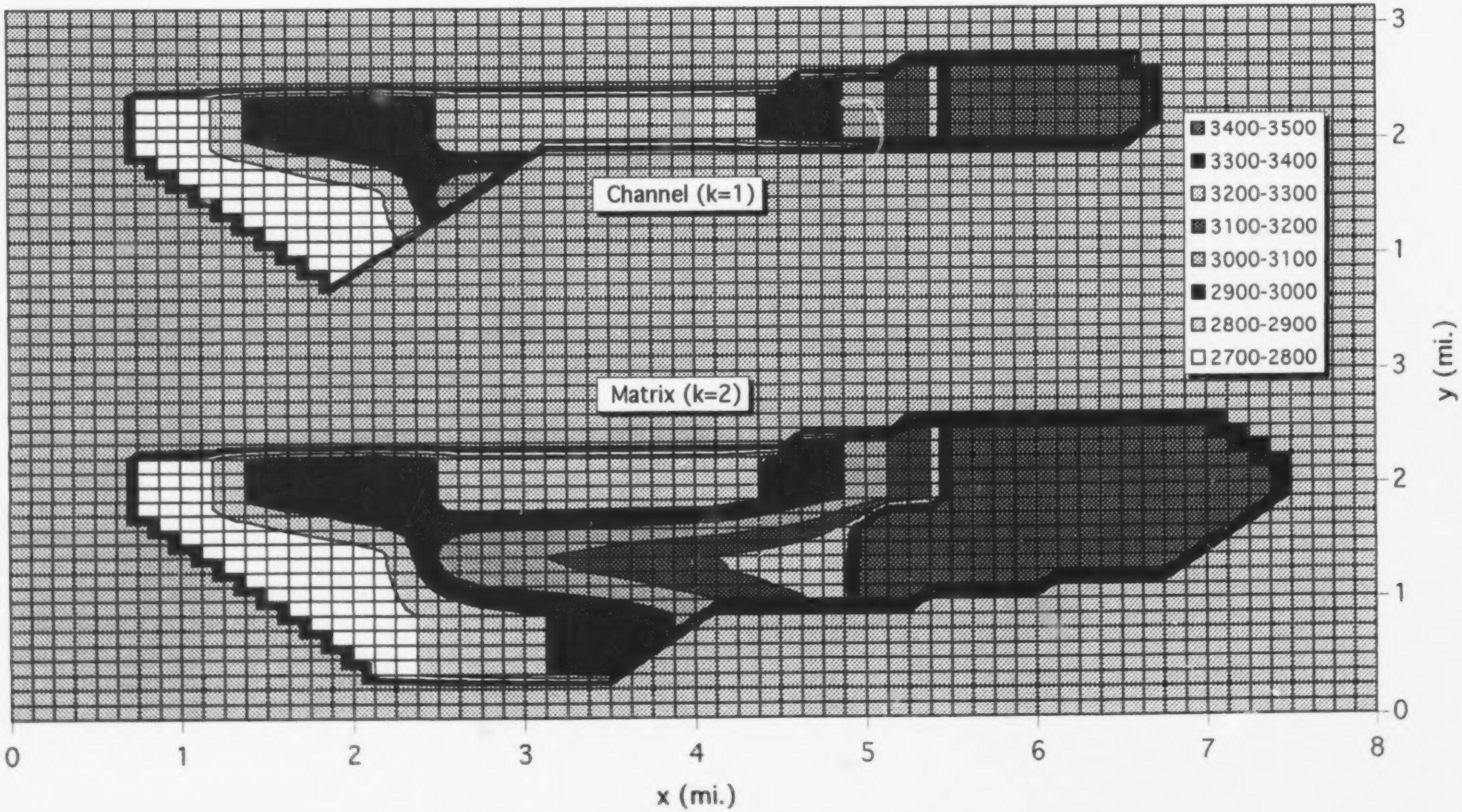

Figure 2.23(d): Initial (Nov-87) Bubble Point p_b (psia)

Chapter 3: Well Management System Model

3.1 Well Model

Production of reservoir fluids (Q_o, Q_w, Q_g) will cause the bottomhole pressure $p_{wf}(\mathbf{x})$ of flowing wells to drop below their static levels $p(\mathbf{x})$. This pressure drop will induce pressure gradients within the surrounding porous media. Transient pressure disturbances will propagate away from the flowing wells at a speed determined by the local reservoir characteristics and fluid properties. The intensity of the pressure disturbance will decrease with distance travelled and virtually vanish at some external drainage boundary. Some wells will coincide within the drainage radii of other wells and interference between pressure disturbances will take place. This interference will couple the pressure response between wells, such that changes in production at one well will effect the production in others. Unsteady flow will occur while the early transient propagates out to the external boundary. The pressure will be a function of both time and distance. The time between early and late transient arrivals at the external boundary will mark the period when transitional flow occurs. When the late transient reaches the external boundary, the system enclosed by the external boundary will behave like a tank (Donaldson *et al.* 1985). The flow will become pseudo-steady and the rate of pressure change will be independent of the location within the closed system. Well productivity will become a function of the average system pressure and stabilized inflow conditions will prevail.

The well productivity index (PI) relates standard flow rates (Q_o, Q_w, Q_g) with the pressure difference between external drainage boundary (p) and bottomhole pressure (p_{wf}). Analytical models have been proposed for various external boundary configurations considering unsteady, pseudo-steady, and steady-state flows. Peaceman (1978) used a single-phase steady-state radial flow model, relating well block pressures to flowing pressures at equivalent radii from block centers. The relationship has been extended to multi-phase flow using relative permeabilities.

$$
\begin{aligned}
Q_o(\mathbf{x}) &= \mathrm{PI}\frac{\lambda_o}{B_o}[p(\mathbf{x}) - p_{wf}(\mathbf{x})] \\
Q_w(\mathbf{x}) &= \mathrm{PI}\frac{\lambda_w}{B_w}[p(\mathbf{x}) - p_{wf}(\mathbf{x})] \\
Q_g(\mathbf{x}) &= \mathrm{PI}\left(\frac{\lambda_g}{B_g} + R_{so}\frac{\lambda_o}{B_o} + R_{sw}\frac{\lambda_w}{B_w}\right)[p(\mathbf{x}) - p_{wf}(\mathbf{x})]
\end{aligned}
\tag{3.1}
$$

All well rates are explicitly, rather than implicitly, incorporated into the reservoir flow model described in Appendix A1. Grid block pressures are referenced at the contemporaneous reservoir state at time (t^n). Production from completion intervals are modeled as point sinks located in specific reservoir volume elements. Wells that penetrate multiple reservoir elements are approximated as a collection of point sinks. Injection wells are treated in the same manner as production wells. Total flows are distributed between grid blocks assigned to particular wells. For vertical wells, these blocks align vertically at different grid layers. Allocation of flow over multiple grid blocks depend on individual layer flow indexes. The layer production flow index (PI) has been estimated by Peaceman (1978) in terms of the areal grid block dimensions (Δx, Δy), wellbore radius (r_w), effective completion interval thickness (h), absolute permeability (K) and a skin factor (S):

$$PI(z;x,y) = \left. \frac{0.00708\,K\,h}{\ln\left(\frac{0.121\sqrt{\Delta x \Delta y}}{r_w}\right) + S} \right|_{(x,y,z)} \qquad (3.2)$$

The conversion factor in the numerator of Eqn (3.2) is consistent with the field units adopted in this work. All wells in the Chedderville Viking "A" pool are vertical. The wellbore radius (r_w) is approximated by the outer casing radius (r_w=5.5 inches) common to all well completion intervals. Wells fully penetrate the bottom layer of the two-layer reservoir model characterized in Section 2.8. The effective completion interval thickness (h) in the bottom layer is assumed to be the same as the mechanical perforation zone thickness (Δz). The absolute permeability (K) is assumed to be the local principal-axis maximum permeability (K_x). Skin effects are due to physical changes in the formation and restricted flow entry at the wellbore. The skin factor (S) accounts for the degree of well damage or stimulation, perforation effects, partial penetration effects, inclined wellbore effects and naturally occurring matrix fractures (Mattax and Dalton 1990). Positive skin factors ($S>0$) reflect the degree of flow restriction while negative skin factors ($S<0$) can be used to characterize a fractured or stimulated well. All wells in the Viking "A" pool have been initially stimulated by acidizing, and some wells by hydraulic fracturing. Therefore, skin effects are assumed to be negligible ($S=0$). A high-permeability top layer is incorporated in the simulation model to provide a channel mechanism for enhanced pressure communication within the reservoir. Only the gross channel functionality is modelled and well flow in this layer is assumed to be shut-in. The actual production from this thin zone is incorporated in the rock matrix layer below. The rock matrix layer implicitly accounts for both channel thickness and permeability through geometric averaging.

The well is a producer if the flowing bottomhole pressure is less than the reservoir pressure. There is no flow when the flowing bottomhole pressure is equal to the reservoir pressure and the well is assumed to be shut in at the static bottomhole pressure.

$$\begin{array}{ll} p > p_{wf} & \text{Production} \\ p = p_{wf} & \text{Shut in} \end{array} \qquad (3.3)$$

Similarly, the well is an injector if the flowing bottomhole pressure is greater than the reservoir pressure.

$$\begin{array}{ll} p < p_{wf} & \text{Injection} \\ p = p_{wf} & \text{Shut in} \end{array} \qquad (3.4)$$

Water injection rates are based on a layer well injectivity index (WI=PI) and total fluid mobilities (Franchi *et al.* 1982):

$$Q_w(\mathbf{x}) = WI \frac{(\lambda_o + \lambda_w + \lambda_g)}{B_w} [p_{wf}(\mathbf{x}) - p(\mathbf{x})] \qquad (3.5)$$

3.2 Surface Facility

Peak liquid production from the pool of wells will be limited by reservoir productivity and the design capacity of the facilities for gathering, separating and treating produced fluids. Separators are pressure vessels designed to separate multiphase fluids into constituent gaseous and liquid streams using flash vaporization. The number of flash separation stages will depend on feedstock composition, temperature and flowing pressures. The stock tank is one stage of separation. Stages are sized to operate most effectively under a narrow band of design pressures and temperatures. Facilities are sized according to the expectation of reservoir productivity and constraining economic criteria. Since pooled production changes with time, the optimum number of stages can also vary with time. In actual field practice, three stages are typically chosen (Chilingarian *et al.* 1986).

The CIM Petroleum Society Monograph No. 1 (1994) describes the risks associated with separator facility sizing. Ultimate reserves are established by an economic limit that depends on hydrocarbon price expectations, operating and capital costs, fiscal regimes and encumbrances such as royalties and net profit interests. Facility capital and operating costs have a direct impact on the ultimate reserves. A facility sized large enough to handle maximum production will have continued high operating costs when volumes decline. A large facility operation may reach its economic limit earlier, with less reserves, than a smaller less-expensive operation that limits the production ceiling. The size of the facility determines the peak fluid production capacity of the entire operation. The ceiling on total fluid further constrains peak oil capacity, which declines with increasing levels of gas-oil and water-oil ratios. The circular argument in facility design can be resolved by staging modular satellites to handle increased production volumes. The economics of scale may be foregone in lieu of the benefits associated with timely expansion.

3.3 System Hydraulics

The stock tank fixes downstream pressure to atmospheric conditions. All upstream pressures, from bottomhole to the stock tank, must adjust to maintain production by overcoming the inertial, viscous, gravitational and interfacial forces that resist flow. A single-layer vertical well model is used to describe well flow behaviour at bottomhole conditions in the reservoir. System hydraulics couple bottomhole pressure to surface pressures through flow in tubings and casings, horizontal and inclined surface flow lines, and flow through restrictions and chokes (Chilingarian *et al.* 1986). Pressure drops will result in all stages from friction losses, changes in kinetic energy and hydrostatic head loss. Some stages may realize additional pressure drops from external work loss due to fluids driving a turbine. External work gains can also be introduced through pumps. The engineering design objective attempts to minimize pressure drops in each portion of the production system such that optimal flow conditions are achieved at maximum efficiency. The integrated system design between reservoir and surface facilities is highly complex and requires accurate relationships between flow rates and pressures.

Back pressures at different system stages are determined by pump and compressor capacities, and by downstream chokes and restrictions. Surface and bottomhole chokes are typically used to regulate flow. The multi-purpose function of the choke is to maintain set point flow rates; maintain sufficient back pressure to prevent sand entry; protect surface equipment; and prevent gas or water coning (Chilingarian *et al.* 1986). When choke flow is critical, changes in downstream pressure do not effect the flow rate or upstream pressure. Critical chokes essentially decouple the flow system at specific points.

In naturally flowing wells, the wellhead pressure (p_{wh}) typically regulates well outflow. Tubing and annulus performance relationships between flow rates and pressure depend on many factors including: temperature, gas-oil ratios, water cuts, fluid properties, interfacial surface tensions, inclination, depth, pipe diameter and pipe smoothness. Aziz *et al.* (1979) have generated gradient curves over a wide range of operating conditions. Hein (1982) gives a stepwise calculation for three-phase flow rates, pressure drops and gas holdup using

Beggs and Brill (1973) method. Calculations are based on multi-phase flow regimes that can occur over incremental segments that span the entire length of pipe. These flow regimes are:

- segregated (stratified, wavy and annular) flow
- intermittent (plug and slug) flow
- distributed (bubble or mist) flow
- single phase flow

Well-bore hydraulics can easily[8] be implemented into the reservoir simulator if the control variable is either the flowing bottomhole pressure or the flow rate. Three-phase fluid properties for viscosity, density, formation volume factors, gas solubility and interfacial surface tension should cover the complete range of pressures and temperatures that may occur over the length of the pipe. Pipe diameters, lengths, inclinations and wall smoothness should also be known. Flowing bottomhole pressures and well flow rates can be determined using Eqns (3.1)-(3.5) coupled with the reservoir flow model described in Appendix A1. Predicted bottomhole saturations can be used to calculate the free gas holdup at bottomhole conditions. With flow rates, bottomhole pressures and gas holdup calculated at each time step, the dynamic well head pressure response can then be predicted using Hein (1982) to explicitly calculate incremental flow regimes and corresponding pressure drops. If the well head pressure is the control variable, then the coupled system is somewhat more difficult[9] to solve for bottomhole pressure and flow rate response. This difficulty arises from the causality of incremental flow regimes. Flow rates must be known in advance to segment these flow regimes.

In pumping wells, artificial lift technologies are used to supplement natural flow with additional energy. The flowing bottomhole pressure (p_{wf}) can be related to the well head pressure (p_{wh}) through an energy or pressure balance:

$$p_{wf} = p_{wh} + \Delta p_h + \Delta p_f + \Delta p_{ke} - \Delta p_{pump} \tag{3.6}$$

---

[8] Results are not presented in this work to maintain scope. The author reports that trial attempts to implement wellbore hydraulics matched specific surface pressure data.

[9] The author anticipates that an implicit solution with flow regime segmentation will be unstable and that an iterative shooting method with explicit pipe calculations should be considered.

Pressure drops are caused by head loss (Δp_h) resulting from fluid in the tubing, friction loss (Δp_f) resulting from irreversible work done, and inertial loss (Δp_{ke}) resulting from changes in kinetic energy. External pump work (Δp_{pump}) can induce a pressure gain in the flow field. For the pump to be effective, it must provide enough external energy to lift liquids to the surface and maintain the well head pressure set point designated by downstream surface operations. This simply implies that the pump will make up the difference between the natural energy within the reservoir, as determined by grid block pressure (p), and the energy required for separating fluids on the surface, as determined by the well head pressure (p_{wh}).

There are six mechanisms for artificially-induced fluid flow:

- centrifugal force
- volumetric displacement
- mechanical impulse
- momentum transfer
- electromagnetic force
- gravity

Pump designs in the petroleum industry are commonly based on the action of centrifugal force and volumetric displacement by mechanical means or by another fluid. Gas lift systems inject high pressure gas down tubing or casing eductors to lift well fluids by gas expansion, fluid column aeration and fluid displacement. Plunger lift systems use gas lift with a free travelling mechanical piston to separate lifted oil. Sucker-rod pumps use string-connected plunger-barrel devices that provide positive displacement on the upstroke. Subsurface hydraulic pumps are downhole devices powered by high-pressure fluids directed from the surface. Positive displacement piston pumps are driven by a hydraulic reciprocating subsurface engine. Jet pumps directly transfer momentum from the power fluid to the working fluid. Electric submersible pumps are multistage centrifugal devices.

The overall pump efficiency is determined by the ratio of useful hydraulic work performed to the input work required to operate the device (Chilingarian *et al.* 1986). The amount of useful work is the product of flow rate capacity with the pressure head differential between inlet and outlet ends. For the pump to operate efficiently at design capacity, its suction end should be within the fluid column below the producing level. Pumping will draw down static fluid levels. Fluid pump-off can occur if the drawdown rate exceeds the well inflow rate over a given period of time. A minimum fluid level above the pump placement is required for uninterrupted operation. The height of fluid flowing in the well depends directly on the flowing bottomhole pressure. Gas locking can also occur when the intake pressure falls below the bubble point pressure. Cyclic loading of free gas and fluid slugs can lead to erratic behaviour and inevitably lead to shut down. The pump should be chosen in advance to match the inflow characteristics of the well. Operations should strictly adhere to a minimum flowing bottomhole pressure constraint, if remedial actions are to be avoided. Remedial actions could involve a well stimulation treatment to increase well productivity, pump modification or replacement, lowering pump setting depths or reducing the production rate with a surface choke. Excessive solids such as sand, scale and weighted mud debris require special attention. Pumps may have to operate below rated capacities to avoid entraining these solids.

The current state of primary production operations in the Chedderville Viking "A" pool is defined on the calendar date of October 1, 1994. At this time, some wells are flowing naturally into a satellite battery gathering system while others are being individually pumped. The simulation model assumes that all current and future production wells are fitted with downhole pumps, each capable of producing at a maximum capacity of 500 barrels per day with a minimum bottomhole pressure constraint of 800 psia.

$$\begin{aligned} Q_o &\le Q_o^{max} = 500\ \mathrm{STB/day} \\ p_{wf} &\ge p_{wf}^{min} = 800\ \mathrm{psia} \end{aligned} \qquad (3.7)$$

The maximum oil flow rate[10] was estimated as the global maximum observed over the entire pool of well production histories. The minimum bottomhole pressure constraint was determined through history matching production and pressure data under historical monthly-averaged flow rate specification. The assumption of pumping wells decouple reservoir flow from well-bore flow, such that the flowing bottomhole pressure becomes the control variable and the pump work becomes a slack variable. The overall production system can be sufficiently determined by the well model in Eqns (3.1)-(3.5), coupled with the reservoir flow model described in Appendix A1, under rate or flowing bottomhole pressure constraints. These production constraints are expressed for oil rate control as:

$$0 \le Q_o \le \min\left(Q_o^{max}, \mathrm{PI}\frac{\lambda_o}{B_o}[p - p_{wf}^{min}]\right) \qquad (3.8)$$

---

[10] In retrospect, a more appropriate flow constraint would limit the maximum liquid production including water from future waterflood operations. The exclusion of water in the well maximum capacity constraint turned out to be innocuous under the additional constraints for flowing bottomhole pressure and water-oil ratios.

and for flowing bottomhole pressure control as:

$$\max\left(p_{wf}^{min}, \; p - \frac{B_o}{PI\,\lambda_o} Q_o^{max} \right) \le p_{wf} \le p \tag{3.9}$$

Peak water injection will be limited by reservoir injectivity and the design capacity of the injection system and water source. The simulation model assumes that all future water injection wells are each capable of injecting at a maximum design capacity of 800 barrels per day with a maximum bottomhole pressure constraint of 7000 psia.

$$\begin{aligned} Q_w &\le Q_w^{max} = 800 \text{ STB/day} \\ p_{wf} &\le p_{wf}^{max} = 7000 \text{ psia} \end{aligned} \tag{3.10}$$

The bottomhole pressure constraint was chosen to limit an assumed reservoir parting pressure. These waterflood constraints are expressed for water injection rate control as:

$$0 \le Q_w \le \min\left(Q_w^{max}, \; WI \frac{[\lambda_o + \lambda_w + \lambda_g]}{B_w} [\, p_{wf}^{max} - p] \right) \tag{3.11}$$

and for flowing bottomhole pressure control as:

$$p \le p_{wf} \le \min\left(p_{wf}^{max}, \; p + \frac{B_w}{WI\,(\lambda_o + \lambda_w + \lambda_g)} Q_w^{max} \right) \tag{3.12}$$

3.4 Regulatory Rate Constraints

Regulatory constraints may limit monthly oil and gas production. In Alberta, monthly allowables are assigned for each well, individually or in aggregate, by EUB, formerly known as the Energy Resources Conservation Board (ERCB). This government agency is empowered by provincial statutes to regulate responsible development and enforce penalties to discourage unauthorized overproduction. Production limits on specific pools, and enhanced recovery projects, are established by the Board's assessment of conservation, equity and environmental impact. The Allowables Handbook (ERCB) describes the accounting system for calculating monthly production allowables. The allowables system is structured on a base maximum rate limitation (MRL) that assigns the daily rate for a single well and a base gas-oil ratio (GOR). Both bases are published in the MRL Order (ERCB) several days prior to the month in which it applies. For Chedderville Viking "A", the single well base MRL, and the base GOR, have remained constant for all wells, from the initial calendar date (1-Nov-1987) to the current date (1-Oct-1994).

$$\begin{aligned}\text{Base MRL} &= 88 \text{ STB/day}\\ \text{Base GOR} &= 1.129 \text{ Mscf/STB}\end{aligned} \tag{3.13}$$

Monthly base allowables are calculated on the basis of cumulative monthly production over the calendar days in a specific month.

$$\begin{aligned}\text{Base Oil Allowable} &= \text{Base MRL} \times \text{days in month}\\ \text{Net Gas Allowable} &= \text{Base GOR} \times \text{Base Oil Allowable}\end{aligned} \tag{3.14}$$

The intention of the net gas limitation is to maximize primary oil recovery by conserving solution gas and to discourage excessive flaring or waste. GOR penalty factors are introduced to limit the monthly net gas produced. Gas credits are awarded for GOR penalty relief when gas is gathered, or used as lease and battery fuel, rather than flared. The monthly net gas produced is calculated as the total monthly gas produced, less gas gathered, less gas used as lease or battery fuel. The net gas allowable is the amount of produced gas that can be flared on a monthly basis, without incurring a penalty. A produced GOR is calculated as:

$$\text{Produced GOR} = \frac{\text{Gas Produced} - \text{Gas Gathered}}{\text{Oil Produced}} \tag{3.15}$$

GOR penalty factors reduce the monthly oil allowable. No GOR penalty factors apply when the producing GOR is below base GOR, otherwise, the penalty factor decreases the base oil allowable proportionately with the excess of producing GOR over the base GOR. The adjusted MRL is referred to as the penalized MRL.

$$\text{Penalized MRL} = \frac{\text{Base GOR}}{\text{Produced GOR}}\ \text{MRL} \tag{3.16}$$

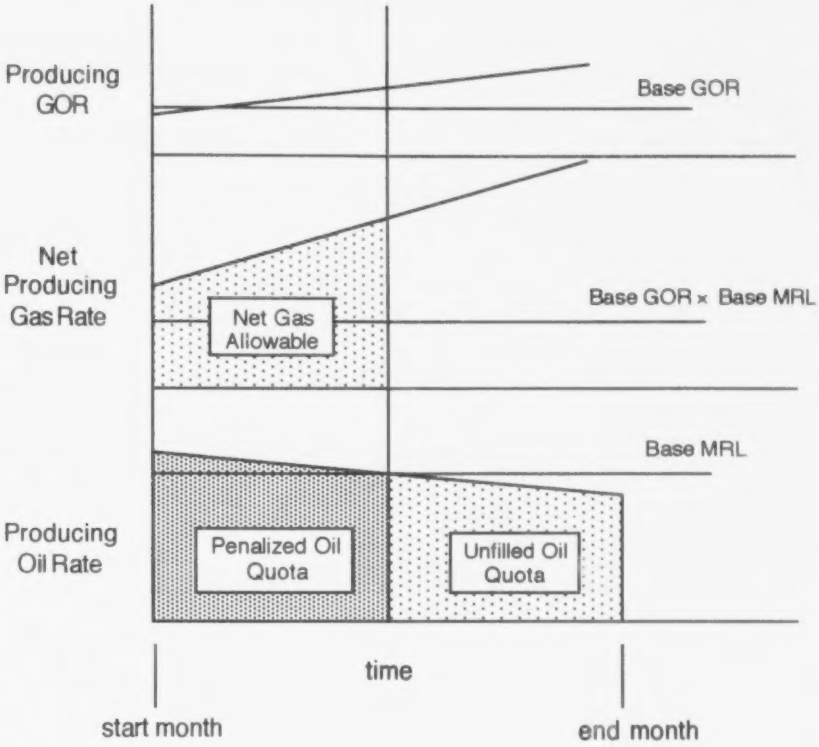
Producing GOR
Base GOR
Net Producing Gas Rate
Net Gas Allowable
Base GOR × Base MRL
Base MRL
Producing Oil Rate
Penalized Oil Quota
Unfilled Oil Quota
time
start month
end month

Figure 3.1: Monthly Rate Limitations

Figure 3.1 illustrates the effect of monthly rate limitations. In essence, the base allowable and base GOR set monthly quota ceilings[11] on cumulative oil and cumulative net (flared) gas that can be produced over monthly cycles. Gas production takes precedence and penalizes oil production if it reaches its quota ceiling first. When this occurs, the unfilled portion of the allowable oil quota is foregone for that month. The temptation to cheat and overproduce is quickly extinguished by the overproduction penalty structure. All penalties are payable in oil. A monthly overproduction penalty is assessed at 50% of the volume in excess of 110% of the adjusted oil allowable. Monthly over- or underproduction, and the monthly overproduction penalty, is added to a cumulative production status. A further 20% cumulative status penalty is assessed for each month that the overproduction status remains above 10% of the adjusted MRL for three consecutive months. This penalty also accumulates with the overproduction status. ERCB expects operators to retire[12] overproduction by reducing production levels below penalized MRL until the cumulative status reaches zero. Prolonged overproduction can lead to the well being shut in by law.

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[11] The current month's penalized MRL is calculated using the GOR penalty factor from the third preceding month. Other details involving off-target penalties are also involved. New wells have modified calculations over the first four months of production. These details essentially change the ceiling on monthly quotas by varying degrees. For simplicity, it is assumed that no off-target penalties apply and that the penalized MRL can be approximated using the current month's GOR penalty factor.

Base MRL and GOR can also be assigned to a block of wells in aggregate, and to enhanced oil recovery projects. The pooled production from the block of wells, and recovery projects, are subject to same overproduction penalty structure as described for a single well entity. Some operations can be assigned a good production practice standing, which is not governed by base allowables, but is subject to discretionary production without adversely affecting conservation.

3.5 Control Strategy

Ramirez (1987) gives a thorough treatment on the application of optimal control theory to enhanced oil recovery projects. He uses Pontryagin's Maximum Principle (Pontryagin *et al.* 1962) to solve a class of optimal control problems that determine control policies which extremize specific performance criterion. Performance criteria assume a deterministic economic model using net present value with discounted cash flows. Of particular interest in his book, is the discrete maximum principle applied to the same black oil simulation model described in Appendix A1. Mehos (1986) first formulated the implicit discrete necessary conditions for an adjoint costate model with transversality equations. Profit maximizing injection policies were found for simulated cases of a single five-spot pattern with water and carbon dioxide injection. State variables were defined as the contemporaneous (p, S_o, S_g) for each volume element in the reservoir grid. A control vector was defined in terms of the flowing bottomhole pressure (p_{wf}) for production grid blocks and injection rates (Q_w, Q_g) for injection grid blocks. The discrete costate model had the same finite difference form as the original state equations that describe multi-phase porous media flow. An iterative computational technique was used to solve the system of two-point boundary valued difference equations. State equations were integrated forward in time to forecast production. Costate equations were then integrated backward in time in order to satisfy a terminal transversality boundary condition. An initial guess of optimal controls were recursively refined in a gradient direction determined by the costate equations. A single variable search along the gradient direction was used to find the maximum local improvement in the performance function.

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[12] Suspended wells have no allowable but must carry forward overproduction. Wells should retire overproduction before they can officially be suspended.

The problem of interest in the present work incorporates a probabilistic economic model for the timing valuation of recovery options. Project value is modeled to depend on time, the state of oil price, the state of depletion and an implemented depletion strategy. The depletion strategy consists of waterflood design and investment timing decisions. It also facilitates control decisions in both primary and secondary operations under regulatory constraints. Waterflood response has a causal dependence on the primary depletion state. The branched differential decision process uses dynamic programming techniques, based on the principle of optimality (Bellman 1957), to find investment and operating decision rules that maximize project value. Branched production forecasts are calculated on the basis of the current primary configuration and a fixed waterflood design with heuristic control strategies. The waterflood design is refined manually to improve potential response at a fixed primary depletion state in a feasible waterflood window. Price sensitive investment decision rules are then found for the fixed waterflood design at different primary depletion states, and times, over the life of the project. Further implementation of the discrete maximum principle to iteratively determine nested optimal control policies in a branched decision process would be computationally prohibitive. The degrees of freedom would explode combinatorially!

The control policy adopted for the depletion strategy of Chedderville Viking "A" is based on a more heuristic approach with design-based decisions. This is not necessarily the best policy, but it does reflect actual field decisions. The model chooses not to overproduce under primary MRL regulation. All produced gas is flared rather than gathered. Primary operations assume that the current single well MRL and GOR will continue for another year. High gas-oil ratio producers are designated to be shut-in at the end of that year. The remaining wells are reclassified under a new block MRL status and reassigned with an aggregate primary MRL based on the sum total of original single well MRLs. The current single well GOR is applied to the new pooled aggregate. At this time, a ten year window for pattern waterflood is assumed to open up. This timing window corresponds to the admissible depletion states remaining in the twenty year life planned for primary production. Good production practice is assumed to apply for a twenty year pattern waterflood. The practice chooses to initially limit aggregate oil and gas production, and allow water injection to repressurize the reservoir above the bubble point pressure. Water injection is maintained at maximum admissible rates for the duration of the project.

Individual wells are regulated independently from a pooled aggregate while they operate above the bubble point pressure. Well workovers and installation of new equipment are assumed not to interrupt production continuity, and are implicitly scheduled over monthly production cycle downtimes.

3.6 Well Spacing

Many wells will produce from the same reservoir pool. As new wells are drilled and go online, they will be continually controlled at design rates and pressures to accommodate bottomhole conditions, downstream flow conditions and regulatory constraints. The placement and number of wells will have design criteria based on both economic and reservoir engineering foundations. In theory, a single well can drain all the moveable oil from a pool given a sufficiently large time. As the well is produced, the pressure gradient established in the reservoir will move out towards the physical boundaries. The production rate will decline proportionally with the decline in average reservoir pressure. Additional wells will accelerate both pooled production and the decline in average reservoir pressure. Pressure gradients from wells that are close together will generally interact sooner than those far apart. When well pressure gradients interact, the effective drainage area per coupled well will be reduced, and consequently, the oil recovered per coupled well will also be reduced. The design production well spacing should attempt to delay interaction between pressure gradients for as long as possible. Each additional well will provide a varying degree of acceleration to the pooled production revenue. Single well contributions to pooled production will generally diminish as the well spacing exceeds a critical density. The optimum number of wells can be determined by the net incremental value of oil recovered by adding each additional well. The expected incremental value will depend on cash flow forecasts based on predicted production, price models and well costs. This is not an easy problem to solve. Even if oil prices were known with certainty, and the reservoir was characterized exactly, the optimal placement, timing and subsequent control of wells using the discrete maximum principle (Mehos 1986, Ramirez 1987) would require a control vector whose dimension would be several factors of the grid partition. This could prove to be computationally prohibitive for a field-wide application.

In practice, regulations constrain the minimum well spacing to regular production spacing units on an areal grid. Initially, new wells are drilled to delineate reservoir boundaries according to the geological and geophysical expectations of oil rich zones. Infill drilling programs may attempt to tap the more productive zones first, as more information becomes available about reservoir structure, characteristics and trends. These programs will consider drilling blocks of infill wells according to the expected economic benefits.

3.7 Primary Control Policy

Wells may be independently, or collectively, toggled[13] on and off between maximum admissible rates established by well productivity and no-flow shut-in states. Monthly production cycles can be as short as a few days of continuous operation in order to adhere with the quotas established by regulatory authorities. Wells can also be regulated at intermediate rates for longer hours of monthly production to satisfy the same constraints. The choice in control may effect the long term recovery by effecting oil production in the short-term.

The choice between high rate (short pulse) and intermediate rate (longer bandwidth) production cycles may affect producing gas-oil ratios. This choice in control can affect the monthly cycle productivity by manipulating unfilled oil quotas. Figure 3.2 illustrates how the producing gas-oil ratio ($\overline{GOR}$) effects unfilled monthly oil quotas. When the oil production rate ($\overline{Q}_o$) is above the base MRL, the time to fill the monthly oil quota (τ_o) will be less than the calendar days in the month. When the producing $\overline{GOR}$ is above the base GOR, the time for gas to fill its monthly quota (τ_g), at a rate of $\overline{GOR} \times \overline{Q}_o$, will be less than the time (τ_o) for oil.

$$\int_0^{\tau_o} \overline{Q}_o dt = MRL \times (month_{end} - month_{start})$$

$$\int_0^{\tau_g} \overline{GOR} \times \overline{Q}_o dt = GOR \times MRL \times (month_{end} - month_{start})$$

$$\Delta t_{produce} = \min(\tau_o, \tau_g) \tag{3.17}$$

If the oil rate remains constant over the monthly production cycle, then the unfilled volume of the oil quota foregone will be $\overline{Q}_o \times (\tau_o - \tau_g)$. An optimal control policy, under regulatory MRL and GOR constraints, would attempt to minimize the producing gas-oil ratio, so that well productivity could fill the monthly oil quota up to its ceiling.

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[13] This is bang-bang control when switching between extremal control states.

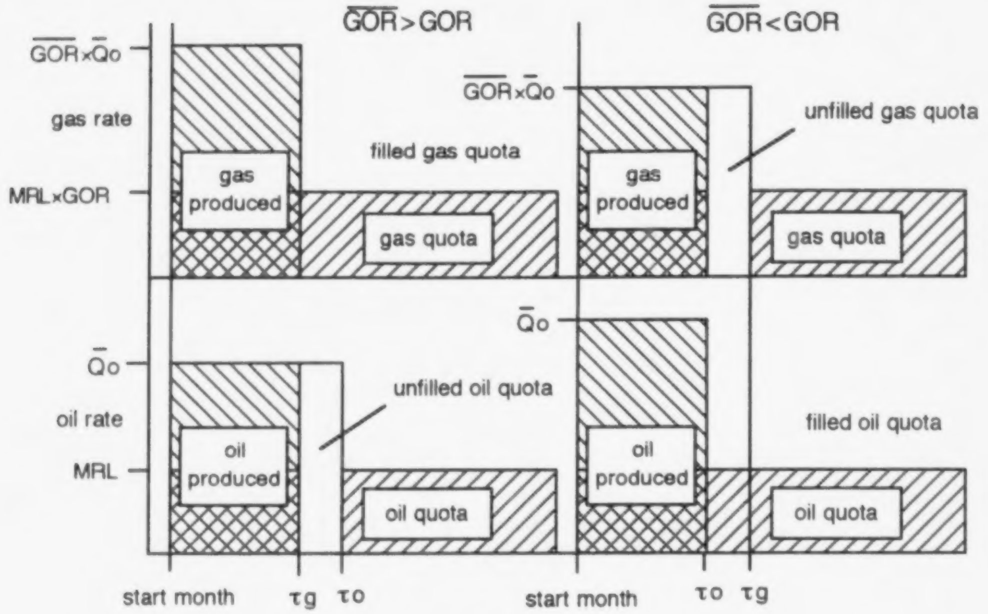
$\overline{GOR}$>GOR
$\overline{GOR}$<GOR
$\overline{GOR}\times\bar{Q}o$
gas rate
MRL×GOR
gas produced
filled gas quota
gas quota
$\overline{GOR}\times\bar{Q}o$
gas produced
unfilled gas quota
gas quota
$\bar{Q}o$
oil rate
MRL
oil produced
unfilled oil quota
oil quota
$\bar{Q}o$
oil produced
filled oil quota
oil quota
start month
τg
τo
start month
τo
τg

Figure 3.2: Producing GOR Effects on Unfilled Oil Quota

The producing gas-oil ratio depends on the reservoir state (p, S_w, S_g) in the well grid block.

$$\overline{GOR}\ (p,S_w,S_g) = R_{so} + R_{sw}\frac{\lambda_w B_o}{\lambda_o B_w} + \frac{\lambda_g B_o}{\lambda_o B_g} \qquad (3.18)$$

These states are coupled by the reservoir flow model described in Appendix A1. The producing gas-oil ratio will inevitably increase as free gas evolves from solution. Primary control under MRL regulation will only delay the inevitable. Independent control of single wells may inadvertently change the reservoir state for other wells. The system is coupled and the ensemble of wells should be orchestrated in unison.

When the producing gas-oil ratio is below the base GOR, the minimum set point rate should be chosen as the base MRL. The selection between maximum admissible or MRL set point rates is inconsequential as long as the cumulative monthly oil production meets the monthly allowable oil quota. If well productivity cannot sustain the MRL set point, then the control rate should be the maximum admissible rate under pumping or flowing conditions. Maintaining MRL or lower set point rates will ensure production continuity without toggling the well off.

Higher than MRL set point rates will lead to cyclic transitions between on and off states as allowable quotas are met. Monthly production bandwidths will get shorter as the rate increases. A limiting minimum bandwidth is determined by the maximum admissible rate. Long production intervals, with intermediate or low set point rates, may not necessarily be the best course of action. The inappropriate choice in rate control may prematurely fill the well block with a dominating free gas saturation.

The primary control policy proposed in this work is based on bubble point pressure hysteresis. The following causal argument assumes saturated oil conditions in the well block which is characteristic of higher producing gas-oil ratios. Well blocks are assumed to be outside of the gas cap. When the well starts its production cycle, the reservoir block pressure falls below its static level, and free gas differentially evolves from solution. Mobile free gas will be produced, along with dissolved gas in oil, at the set point rate. Free gas and reservoir liquids will flow from adjacent grid blocks under induced pressure gradients. In the absence of other wells, a pseudo-steady flow will quickly stabilize over an initial transitionary period[14]. The local free gas saturation will fall if the sustained gas production rate is greater than the combined rates of free gas evolution and migration from surrounding blocks. The local bubble point will drop and adjust to the new vapour-liquid ratio within the producing well block. When the well is shut at the end of its production cycle, the local grid block pressure will rise back to a new static level. Vapour-liquid equilibrium will be reached and free gas evolution will stop. Pressure gradients will diminish and gas migration will halt. The vapour-liquid ratio will remain at the new level established by the adjusted bubble point. For this tight reservoir, it is assumed that the rate of inter-block free gas migration, outside of the gas cap, is small with respect to the local rate of free gas evolution.

$$\frac{\partial}{\partial t}\left(\phi \frac{R_{so} S_o}{B_o}\right)\Bigg|_{ijk} >> \nabla \cdot \tilde{K} \cdot \left[\frac{\lambda_g}{B_g} \nabla (p + p_{cgo} - \rho_g g z)\right]\Bigg|_{ijk} \qquad (3.19)$$

Bleeding gas at low set point rates will allow differential gas evolution to balance produced gas volumes, and thereby have little effect on the local bubble point.

$$\Delta\left(\phi \frac{R_{so} S_o}{B_o} \Delta \mathbf{x}\right)\Bigg|_{ijk} \approx Q_g\Big|_{ijk} \Delta t_{produce} \qquad (3.20)$$

---

[14] This transitionary period (Dake 1978) was estimated at less than a day .

The next cycle will start at a lower static grid block pressure, and an increased gap between local bubble point and static grid block pressures will persist. Higher set point rates will cause larger pressure swings with shorter production bandwidths. Pressure swings will initially cause free gas to evolve from solution. If, for the same pressure swing, the gas production rate is higher than the gas evolution rate,

$$\Delta\left(\phi \frac{R_{so} S_o}{B_o} \Delta \mathbf{x}\right)\Big|_{ijk} < Q_g\Big|_{ijk} \Delta t_{produce} \qquad (3.21)$$

then the local vapour-liquid ratio will decrease. This can occur if production is more responsive to pressure than free gas evolution is to pressure. This implies that the local bubble point pressure for larger pressure swings will drop to lower levels than those resulting from smaller pressure swings. If a fixed volume of fluid is produced over comparable pressure swing cycles, then grid block pressures will be approximately the same after a stabilization period at the cycle end. Bubble point pressures, however, will lock onto different levels. The next cycle will start at a lower static grid block pressure and a lower local bubble point that corresponds to a reduction in the local gas-oil ratio. The gap between local bubble point and static grid block pressures will still persist, but will be less for larger pressure swings than for smaller ones. In this manner, a bang-bang control policy producing at the maximum admissible rate with short monthly pulses can delay higher producing gas-oil ratios.

The proposed primary control policy was tested with the simulation model for the first year of primary production forecasting. It did delay higher gas-oil ratios and was adopted throughout the remaining forecasts. An accounting system was used to regulate oil and gas production. Explicit time steps were set to coincide with individual well production cycles. Wells were toggled on and off between maximum admissible rates established by well productivity (Eqns 3.7-3.9) and no-flow shut-in states. Monthly production accounts were accumulated for each well to satisfy MRL and GOR regulatory constraints.

3.8 Secondary Control Policy

Primary operations assume that the current wells will continue to produce for another year with the exception of those in the developing gas cap. High gas-oil ratio producers are designated to be shut-in at the end of that year, and a ten year timing window for pattern waterflood is assumed to open up. The primary state of the reservoir over the waterflood timing window is assumed to be saturated with rising levels of free gas. Good production practice is assumed to apply for a twenty year pattern waterflood.

The practice chooses to initially limit aggregate oil and gas production, and allow water injection to repressurize the reservoir above the bubble point pressure. Water injection is maintained at maximum admissible rates for the duration of the project. If fluid production is not managed in the early phase of the waterflood, average reservoir pressures may continue to decline as a result of imbalances between water injection and fluid production rates. Declining pressures would free more gas from solution. Waterflood energy would then be expended on recompressing free gas instead of displacing an oil bank. This inefficiency would render the waterflood to be virtually ineffective. Oil mobility will decrease in the presence of increasing free gas and water saturations. In contrast, gas mobility will increase with increasing free gas and water mobility will increase with increasing water. The piston-like displacement efficiency of the waterflood sweep depends on the mobility ratio between water and oil (Willhite, 1990, p87-89). Under waterflood pressure, injected water would start to expand and flow towards producing wells. An oil bank would form as it gets compressed ahead of the water front. The leading oil would have a maximum mobility in the absence of free gas. This would occur at the bubble point pressure. Further compression above the bubble point would direct waterflood energy into accelerating the displacement process through heightened pressure gradients. The theoretical limit of waterflood efficiency would be determined by the residual oil saturation and the three-dimensional sweep in both vertical and horizontal directions.

The secondary control policy for Chedderville Viking "A" is based on these physical mechanisms and an implicit utility function specific to corporate demands. Waterflood injection capabilities are limited by the pattern design, well injectivities, design capacity of the injection system, surface water source and reservoir characteristics. A fixed waterflood design may exhibit fluctuations in water injection rates and pressures. Injection rates will initially drop as radial flow fronts from point sources interact with reservoir fluids in the surrounding porous media. Injection rates will then rise as water displaces or dissolves free gas and fills its pore space. Injection rates will continue to rise until water breaks through at adjacent producing wells. After water breakthrough, injection rates will fall as the reservoir floods out with increasing pressure. As high water-oil producers are shut in, underground water flows will be diverted towards other producing wells. The choice in water injection set point rates are assumed to be weakly subject to explicit operating costs. Injection operating costs are assumed to be implicitly lumped with overall production operating costs. The choice in waterflood injection rates, over the admissible range, are only based on advanced timing, or acceleration of the production revenue stream. Higher injection rates will hasten oil displacement and accelerate production revenues. Higher injection rates will also initiate earlier water breakthrough times and subsequent advances in rising water-oil ratios. The premise that production revenues should come sooner than later, fixes injection rate setpoints to those maximum admissible for individual injection wells.

The choice in production rates is not as obvious as the choice in injection rates. One extreme would be to shut in all producers, until the reservoir is repressured above the bubble point, and then regulate production to maintain undersaturated bottomhole conditions. This strategy has flaws. Shutting in all producers will eliminate production revenues over the repressurization period, which may be measured in years. Water may also advance through the top high permeability channel and saturate the rock matrix below. This would interfere with the formation of an oil bank ahead of the water front when producing wells are open to flow. The other extreme would consider producing at maximum admissible rates under the good production practice umbrella. This, however, would prove to be a futile waterflood effort and lead to similar recoveries as observed in primary production.

The problem at hand is to choose production rates that balance corporate head office's demand for an uninterrupted revenue stream with a control policy that ensures repressurization without channelling water. The challenge was met with a compromise solution. All wells operating with saturated bottomhole conditions[15] were pooled into one control group, while the remaining wells were treated as single control entities. Single control entities were continuously produced at maximum admissible rates while local bottomhole conditions remained undersaturated. Single control entities were reclassified and demoted to the aggregate control group, when the entity's bottomhole condition switched from undersaturated to saturated. The aggregate control group was assigned an in-house MRL and GOR that satisfied both utility demands and repressurization objectives. The in-house MRL and GOR assignments were established on the basis of an implicit utility function. It was assumed that corporate head office would demand an initial waterflood revenue stream to be at least as much as that expected from continued primary production. The group was controlled in the same bang-bang manner described for primary control in Section 3.7. Wells that repressured above the bubble point were promoted to single control entity status and allowed to produce at maximum rates. Individual production wells were regulated over the course of waterflood, either independently or within a group, to attain the objectives set forth.

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[15] Local bottomhole conditions depend on whether the reservoir pressure is above or below the local bubble point in the well grid block.

Chapter 4: History Match

4.1 Historical Controls

Historical controls for Chedderville Viking "A" may or may not have been based on a control strategy. These controls would have reacted to the actual conditions encountered during operation. The decisions would have been based on timely information about well particulars. This information would be confidential and not available to the general public. The following account of historical control is an interpretation deduced from historical production data listed in Table 4.1. Historical data indicates that decision-makers were using ad-hoc controls.

New wells have a grace period of four months before MRL regulation kicks in. Rates and monthly bandwidths were adjusted over this initial trial period to determine production response. Pumps were most likely installed in some wells. Most wells were initially operating at undersaturated bottom-hole conditions. Producing gas-oil ratios were below the base GOR. High gas-oil ratio wells were encountered in a developing gas cap. These wells were choked back to produce at lower oil rates so that gas production would stabilize within allowable limits. Reservoir pressures declined as more wells were produced. Jumps in producing gas-oil ratios signalled the sudden release of mobile free gas as bottomhole pressures dropped below local bubble point pressures. This occurred sequentially down the east-west dip of the pool. Daily oil rates were eventually set at intermediate levels with intermediate monthly bandwidths. Cyclic controls reacted to conditions encountered in the field. Stabilized gas rates were managed while monthly oil production declined. Historical data highly correlates monthly gas production with the net gas allowable, indicating that produced gas was flared and not gathered. Historical data also highly correlates monthly oil production with the net oil allowable, indicating that decision makers adhered to MRL regulations. The observed decline in oil production is interpreted as a consequence of the control choices made to satisfy regulatory constraints and not the decreased well capabilities associated with reservoir pressure decline. It is conjectured that maximum admissible rates are above current producing levels and that physical production ceilings will remain higher for some time before the actual pressure decline becomes the limiting factor.

4.2 Simulation Controls

A base time step was fixed at ten days to ensure numerical stability. The instantaneous set point oil rate for each well was fixed at historical monthly averages for set point durations fixed at historical monthly hours of operation.

Consecutive time steps were determined using an accounting system. Explicit time steps were set to coincide with individual well production cycles. All producing wells were turned on and monthly production counters set to zero at the beginning of each monthly cycle. Consecutive time steps were marked by the minimum between the base time step, remaining time for the monthly accounting cycle and the remaining durations over all wells. Gas produced by individual wells over each time step was accumulated in corresponding counters. Relevant wells were toggled off and the next step initiated. Cycle-averaged gas rates were calculated for each well by dividing accumulated monthly gas by the hours of production. Cycle-averaged gas rates were recorded for the current month at the end of the monthly cycle. Calendar time was used for each month. Instantaneous aggregate pool production rates and average reservoir pressure were recorded at each time step. Instantaneous bottomhole pressures for each well were also recorded at each time step.

4.3 Simulation Results

Table 4.2 lists the final results for simulator matched gas production, for the given schedule of monthly oil rates and hours of operation, obtained at the end of the iterative modelling process undertaken for this project. Figures 4.1(a)-(n) show the fit between historical gas production data and simulation matched results for 14 individual wells in chronological order. The second well 06-15-37-7W5 in the developing gas cap could not be fit with this model and was toggled off midway through the simulation. Most gas matches were adequate to good. Diverging results for 14-09-37-7W5 and neighbouring wells in 1993 were attributed to the pressure disturbance that occurred when the lower Mannville perforation zone was shut in. Figures 4.2(a)-(n) show the fit between historical pressure data and simulation predicted results for instantaneous reservoir pressure and flowing bottomhole pressure. The second well 06-15-37-7W5 pressures could not be fit with this model, but the remaining wells showed good matches. The bottomhole pressure spikes represents the cyclic response to bang-bang rate controls.

Figure 4.3(a) shows a general decline in average reservoir pressure starting in 1990. Figure 4.3(b) shows the cumulative gas production match for the entire pool. Large initial deviation is a result of the poor fit for 06-15-37-7W5. Figure 4.3(c) shows are good fit when the first two wells in the developing gas cap are excluded. Figure 4.4(a) shows the simulated instantaneous pooled oil production rate from the reservoir. Pooled monthly production cycles correspond to the sum of individual well cycles at different rates and different duration bandwidths. Figure 4.4(b) shows similar behaviour for pooled instantaneous gas production rates. The actual instantaneous oil and gas rate behaviour may or may not resemble simulated results. Bottomhole pressures were probably the set point control and oil production rates were allowed to vary over production cycles. The assumption that individual production cycles started at the beginning of each month and were sustained for a single band may also affect the shape of these curves. These details could not be verified with the information made publicly available.

Figures 4.5(a)-(e) show the simulated current reservoir depletion state at the end of the history match period. The central pressure disturbance is highly visible in Figure 4.5(a). No changes are observed in the water saturation distribution in Figure 4.5(b), which is to be expected for a reservoir with no initially mobile water zone. Figures 4.5(c)-(e) show the oil saturation, gas saturation and bubble point pressure distributions. The initial gas cap is observed to have grown, with a new free gas zone beginning to develop in the thickest portion of the lower reservoir.

4.4 Calibration Summary

The reservoir description and black oil simulation model gave a reasonable match for the overall pool performance. Wells in the vicinity of gas cap and central pressure disturbance could not be adequately modelled throughout the historical seven year period. These wells were 06-15-37-7W5, 14-09-37-7W5 and 16-09-37-7W5. The remaining eleven wells showed satisfactory to good fits for both pressure and gas production. These wells are located in the oil rich zone which is designated for pattern waterflood. The history match validated the model to an acceptable degree. The model is assumed to provide reliable forecasts for future production in the lower portion of the reservoir.

	Well	16-09-37-7W5				Well	06-15-37-7W5				Well	08-13-37-8W5		
	Battery	16-09-37-7W5		SINGLE		Battery	06-15-37-7W5		SINGLE		Battery	06-13-37-8W5		SATELLITE
	Casing	Depth (ft)	Dia (in)	Wt (lb/ft^3)		Casing	Depth (ft)	Dia (in)	Wt (lb/ft^3)		Casing	Depth (ft)	Dia (in)	Wt (lb/ft^3)
	Surface	1337.6	8.6	2.23		Surface	1325.5	9.6	3.35		Surface	1379.6	9.6	3.35
	Prod	8759.8	5.5	2.23		Prod	8579.4	5.5	2.23		Prod	9186.4	5.5	2.23
Date	Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d	Date	Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d	Date	Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d
Oct-87					Oct-87					Oct-87				
Nov-87	477	38.2	34.8	0.0	Nov-87					Nov-87				
Dec-87	528	21.2	54.1	0.0	Dec-87					Dec-87				
Jan-88	288	36.9	22.8	0.0	Jan-88					Jan-88				
Feb-88	696	25.9	66.2	0.0	Feb-88					Feb-88				
Mar-88	744	18.1	38.2	0.0	Mar-88					Mar-88				
Apr-88	480	25.1	35.8	0.0	Apr-88					Apr-88				
May-88	579	25.2	39.2	0.0	May-88					May-88				
Jun-88	705	15.8	34.9	0.0	Jun-88					Jun-88				
Jul-88	722	20.0	38.7	0.0	Jul-88					Jul-88				
Aug-88	739	18.1	36.4	0.0	Aug-88					Aug-88				
Sep-88	588	20.4	39.5	0.0	Sep-88					Sep-88				
Oct-88	728	18.7	33.6	0.0	Oct-88					Oct-88				
Nov-88	720	17.3	31.5	0.0	Nov-88					Nov-88				
Dec-88	568	22.5	31.8	0.0	Dec-88					Dec-88				
Jan-89	740	18.8	28.8	0.0	Jan-89					Jan-89				
Feb-89	648	17.8	28.4	0.0	Feb-89					Feb-89				
Mar-89	528	19.6	28.1	0.0	Mar-89	636	102.6	314.5	0.0	Mar-89				
Apr-89	432	28.4	33.9	0.0	Apr-89	676	71.6	345.4	0.0	Apr-89				
May-89	552	25.2	28.1	0.0	May-89	735	53.6	331.7	0.0	May-89				
Jun-89	711	18.3	26.8	0.0	Jun-89	720	49.2	299.1	0.0	Jun-89				
Jul-89	744	17.4	26.9	0.0	Jul-89	185	49.4	345.8	0.0	Jul-89				
Aug-89	744	15.9	25.5	0.0	Aug-89	288	33.3	314.1	0.0	Aug-89				
Sep-89	720	20.1	28.6	0.0	Sep-89	240	42.5	321.2	0.0	Sep-89				
Oct-89	525	16.9	40.3	0.0	Oct-89	176	58.7	365.0	0.0	Oct-89				
Nov-89	720	17.5	23.7	0.0	Nov-89	108	65.0	364.4	0.0	Nov-89				
Dec-89	744	15.8	27.3	0.0	Dec-89	139	63.3	329.7	0.0	Dec-89				
Jan-90	744	15.0	26.2	0.0	Jan-90	173	67.3	429.9	0.0	Jan-90				
Feb-90	672	16.1	24.1	0.0	Feb-90	189	64.0	382.2	0.0	Feb-90				
Mar-90	744	16.2	25.1	0.0	Mar-90	155	86.7	441.3	0.0	Mar-90	125	408.6	265.8	12.3
Apr-90	720	14.8	25.4	0.0	Apr-90	142	71.0	456.5	0.0	Apr-90	45	390.5	274.5	0.0
May-90	744	14.7	25.9	0.0	May-90	144	83.3	411.1	0.0	May-90	575	352.0	282.7	0.1
Jun-90	720	15.0	26.3	0.0	Jun-90	234	57.2	364.4	0.0	Jun-90	400	367.1	300.9	0.0
Jul-90	432	18.7	22.7	0.0	Jul-90	160	72.9	415.8	0.0	Jul-90	54	359.8	293.4	0.3
Aug-90	744	18.7	26.3	0.0	Aug-90	282	53.4	425.3	0.0	Aug-90	168	357.2	292.6	0.7
Sep-90	720	16.7	26.9	0.0	Sep-90	143	73.2	418.8	0.0	Sep-90	189	361.6	291.2	0.1
Oct-90	720	16.3	26.0	0.0	Oct-90	168	79.3	398.6	0.0	Oct-90	188	364.2	286.8	0.1
Nov-90	720	18.0	29.5	0.0	Nov-90	117	70.9	326.9	0.0	Nov-90	204	343.4	276.9	0.1
Dec-90	659	17.4	26.9	0.0	Dec-90	120	97.5	337.9	0.0	Dec-90	192	355.8	292.8	0.1
Jan-91	744	18.5	27.6	0.0	Jan-91	142	99.1	323.4	0.0	Jan-91	192	352.3	292.8	3.4
Feb-91	672	18.2	22.9	0.0	Feb-91	166	84.1	308.4	0.0	Feb-91	172	354.5	286.3	0.1
Mar-91	710	16.3	25.2	0.0	Mar-91	262	79.6	263.0	0.0	Mar-91	163	342.1	281.7	0.1
Apr-91	615	17.5	24.4	0.0	Apr-91	286	73.0	276.4	0.0	Apr-91	192	339.1	273.3	0.1
May-91	744	16.7	25.4	0.0	May-91	264	72.6	282.4	0.0	May-91	201	341.4	283.5	0.1
Jun-91	720	15.9	26.0	0.0	Jun-91	288	74.9	263.5	0.0	Jun-91	192	348.1	286.6	0.8
Jul-91	744	15.5	25.1	0.0	Jul-91	264	74.0	285.6	0.0	Jul-91	207	334.3	288.1	0.1
Aug-91	744	14.2	22.8	0.0	Aug-91	240	76.7	226.1	0.0	Aug-91	192	359.7	290.2	0.1
Sep-91	720	14.2	22.4	0.0	Sep-91	260	73.0	235.6	0.0	Sep-91	209	323.0	286.5	0.1
Oct-91	744	12.8	20.7	0.0	Oct-91	240	67.4	248.8	0.0	Oct-91	207	330.7	284.8	0.1
Nov-91	720	13.0	20.7	0.0	Nov-91	334	75.9	226.0	0.0	Nov-91	187	362.0	291.5	0.1
Dec-91	432	12.4	23.1	0.6	Dec-91	336	68.3	230.0	0.0	Dec-91	188	366.1	291.8	0.1
Jan-92	744	12.0	22.5	0.0	Jan-92	291	69.3	250.3	0.0	Jan-92	192	354.7	301.2	0.1
Feb-92	696	20.3	27.2	0.0	Feb-92	265	72.6	205.4	0.0	Feb-92	144	341.0	291.1	0.1
Mar-92	744	20.1	28.8	0.0	Mar-92	359	60.6	188.2	0.0	Mar-92	208	325.1	274.4	0.1
Apr-92	720	19.2	30.3	0.0	Apr-92	336	56.7	231.7	0.0	Apr-92	192	343.1	288.8	0.1
May-92	744	19.1	32.4	0.0	May-92	480	51.8	213.7	0.0	May-92	187	360.7	309.3	0.1
Jun-92	720	18.5	35.1	0.0	Jun-92	466	47.0	192.3	0.0	Jun-92	176	375.8	310.3	0.1
Jul-92	744	18.5	31.8	0.0	Jul-92	312	55.8	276.0	0.0	Jul-92	181	375.0	314.9	0.1
Aug-92	744	17.7	29.3	0.0	Aug-92	265	66.0	320.5	0.0	Aug-92	185	364.7	323.2	0.1
Sep-92	720	16.9	29.8	0.0	Sep-92	240	71.7	295.0	0.0	Sep-92	178	371.7	329.7	0.1
Oct-92	744	16.2	29.4	0.0	Oct-92	205	71.5	244.8	7.1	Oct-92	182	374.4	339.3	0.1
Nov-92	720	16.3	28.4	0.0	Nov-92	166	83.8	218.6	0.0	Nov-92	240	273.0	231.8	0.0
Dec-92	744	15.2	28.4	0.0	Dec-92	208	81.2	204.0	0.0	Dec-92	335	192.0	152.3	0.0
Jan-93	744	15.1	31.4	0.0	Jan-93	290	70.9	196.2	0.0	Jan-93	273	241.8	136.4	0.0
Feb-93	672	14.7	59.2	0.1	Feb-93	334	60.2	129.8	0.0	Feb-93	322	192.5	168.2	0.0
Mar-93	744	14.4	57.5	0.0	Mar-93	191	120.1	75.4	0.0	Mar-93	364	188.8	194.7	0.0
Apr-93	720	13.0	49.0	0.0	Apr-93	106	287.9	559.3	0.0	Apr-93	375	172.5	173.8	0.0
May-93	744	9.6	49.9	0.0	May-93	77	85.7	498.9	0.0	May-93	456	165.0	187.7	0.0
Jun-93	720	11.9	53.7	0.0	Jun-93	696	42.0	24.0	0.0	Jun-93	401	169.6	223.0	0.0
Jul-93	744	12.0	52.8	0.0	Jul-93	672	17.4	15.2	0.0	Jul-93	398	154.4	217.7	0.0
Aug-93	666	11.1	58.3	0.0	Aug-93	552	20.3	46.3	0.0	Aug-93	257	265.6	331.8	0.0
Sep-93	720	9.2	51.9	0.0	Sep-93	648	49.1	35.2	0.0	Sep-93	228	284.2	377.4	0.0
Oct-93	576	7.2	58.4	0.0	Oct-93	744	60.1		0.0	Oct-93	271	252.0	302.4	0.0
Nov-93	720	5.9	49.1	0.0	Nov-93	312	30.1	1.3	4.4	Nov-93	257	248.3	410.0	0.0
Dec-93	744	8.1	47.8	0.0	Dec-93	13	164.9	19.7	0.0	Dec-93	312	173.5	348.1	0.0
Jan-94	744	7.3	48.1	0.0	Jan-94	4	769.9		0.0	Jan-94	372	148.1	409.0	0.0
Feb-94	607	8.0	56.2	0.0	Feb-94	13	932.5		0.0	Feb-94	241	151.8	442.5	0.0
Mar-94	724	7.3	51.8	0.0	Mar-94	25	372.5		0.0	Mar-94	270	134.6	435.4	0.0
Apr-94	720	6.8	50.4	0.0	Apr-94	23	327.5		0.0	Apr-94	198	132.0	433.7	0.0
May-94	744	6.4	49.1	0.0	May-94	14	576.8		0.0	May-94	239	109.3	616.6	0.0
Jun-94	720	6.5	46.6	0.0	Jun-94	17	547.9		0.0	Jun-94	128	177.1	727.4	0.0
Jul-94	528	6.0	52.0	0.4	Jul-94	23	533.6		0.0	Jul-94	239	92.6	686.1	0.0
Aug-94	504	9.2	54.6	0.0	Aug-94	23	517.8		0.0	Aug-94	120	104.2	619.0	0.0
Sep-94	24	196.2	1519.2	0.0	Sep-94	22	532.4		0.0	Sep-94	164	105.0	584.3	0.0

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

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Table 4.1: Chedderville Viking "A" Production History (Oct-94)

	Well	06-13-37-8W5				Well	06-16-37-7W5				Well	08-14-37-8W5		
	Battery	06-13-37-8W5		SATELLITE		Battery	08-18-37-7W5		SATELLITE		Battery	06-13-37-8W5		SATELLITE
	Casing	Depth (ft)	Dia (in)	Wt (lb/ft^3)		Casing	Depth (ft)	Dia (in)	Wt (lb/ft^3)		Casing	Depth (ft)	Dia (in)	Wt (lb/ft^3)
	Surface	1364.5	9.6	3.35		Surface	1351.7	9.6	3.35		Surface	1404.2	9.6	3.35
	Prod	8999.3	5.5	2.23		Prod	8694.2	5.5	2.23		Prod	9225.7	5.5	2.23
Date	Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d	Date	Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d	Date	Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d
Oct-87					Oct-87					Oct-87				
Nov-87					Nov-87					Nov-87				
Dec-87					Dec-87					Dec-87				
Jan-88					Jan-88					Jan-88				
Feb-88					Feb-88					Feb-88				
Mar-88					Mar-88					Mar-88				
Apr-88					Apr-88					Apr-88				
May-88					May-88					May-88				
Jun-88					Jun-88					Jun-88				
Jul-88					Jul-88					Jul-88				
Aug-88					Aug-88					Aug-88				
Sep-88					Sep-88					Sep-88				
Oct-88					Oct-88					Oct-88				
Nov-88					Nov-88					Nov-88				
Dec-88					Dec-88					Dec-88				
Jan-89					Jan-89					Jan-89				
Feb-89					Feb-89					Feb-89				
Mar-89					Mar-89					Mar-89				
Apr-89					Apr-89					Apr-89				
May-89					May-89					May-89				
Jun-89					Jun-89					Jun-89				
Jul-89					Jul-89					Jul-89				
Aug-89					Aug-89					Aug-89				
Sep-89					Sep-89					Sep-89				
Oct-89					Oct-89					Oct-89				
Nov-89					Nov-89					Nov-89				
Dec-89					Dec-89					Dec-89				
Jan-90					Jan-90					Jan-90				
Feb-90					Feb-90					Feb-90				
Mar-90					Mar-90					Mar-90				
Apr-90					Apr-90					Apr-90				
May-90					May-90					May-90				
Jun-90					Jun-90					Jun-90				
Jul-90					Jul-90					Jul-90				
Aug-90	744	127.7	103.0	0.0	Aug-90					Aug-90				
Sep-90	528	160.4	128.1	0.0	Sep-90					Sep-90				
Oct-90	744	222.2	172.7	0.0	Oct-90	63	491.1	223.1	86.0	Oct-90				
Nov-90	120	173.6	117.1	0.0	Nov-90	621	290.1	230.5	0.1	Nov-90				
Dec-90	672	122.3	78.6	0.0	Dec-90	583	291.6	370.1	0.0	Dec-90				
Jan-91	336	173.0	121.2	0.0	Jan-91					Jan-91				
Feb-91	408	138.4	113.6	0.0	Feb-91	213	268.3	200.0	0.1	Feb-91	600	192.3	128.8	0.0
Mar-91	288	224.5	180.1	0.0	Mar-91	234	270.7	231.2	0.1	Mar-91	744	167.5	116.8	0.0
Apr-91	312	226.6	169.6	0.0	Apr-91	244	254.8	215.1	0.1	Apr-91	720	153.6	118.3	0.0
May-91	264	222.4	163.9	0.0	May-91	236	266.4	182.7	0.1	May-91				
Jun-91	312	225.0	160.5	0.0	Jun-91	231	266.1	202.5	0.1	Jun-91	384	168.5	130.4	0.0
Jul-91	288	235.1	176.3	0.0	Jul-91	238	262.9	204.4	0.1	Jul-91	744	88.6	64.1	0.0
Aug-91	240	249.4	178.5	0.0	Aug-91	264	237.9	211.4	0.1	Aug-91	264	241.2	181.0	0.0
Sep-91	312	212.5	162.5	0.0	Sep-91	262	237.5	215.6	0.1	Sep-91	336	195.4	143.8	0.0
Oct-91	288	235.7	180.7	0.0	Oct-91	264	238.6	231.4	0.1	Oct-91	312	214.4	157.8	0.0
Nov-91	264	249.7	183.6	0.0	Nov-91	237	257.7	230.4	0.1	Nov-91	288	211.4	151.1	0.0
Dec-91	240	280.4	209.8	0.0	Dec-91	262	237.7	225.3	0.1	Dec-91	240	258.6	204.1	0.0
Jan-92	240	295.9	225.4	0.0	Jan-92	261	239.5	259.1	0.1	Jan-92	240	272.6	194.2	0.0
Feb-92	216	274.2	220.8	0.0	Feb-92	266	236.1	312.6	0.1	Feb-92	216	286.8	206.3	0.0
Mar-92	240	288.3	219.7	0.0	Mar-92	285	220.8	349.1	0.1	Mar-92	264	243.4	199.4	0.0
Apr-92	264	249.1	183.9	0.0	Apr-92	245	251.0	296.6	0.2	Apr-92	240	271.7	302.1	0.0
May-92	288	234.1	179.8	0.0	May-92	237	223.2	313.4	0.1	May-92	240	268.5	176.4	0.0
Jun-92	264	248.6	201.4	0.0	Jun-92	178	239.5	316.3	0.1	Jun-92	240	273.1	180.0	0.0
Jul-92	504	132.1	105.1	0.0	Jul-92	193	251.1	297.9	0.1	Jul-92	312	208.8	133.8	0.0
Aug-92	480	140.3	90.2	0.0	Aug-92	215	237.2	299.1	0.1	Aug-92	504	129.1	76.1	0.0
Sep-92	264	245.2	180.4	0.0	Sep-92	210	246.2	350.5	0.1	Sep-92	312	170.6	118.8	0.8
Oct-92	336	200.8	140.0	0.0	Oct-92	289	207.2	458.1	0.1	Oct-92	288	228.7	150.0	0.0
Nov-92	408	163.9	110.2	0.0	Nov-92	360	154.7	359.0	0.0	Nov-92	288	229.8	144.4	0.0
Dec-92	334	230.3	111.9	0.0	Dec-92	240	225.7	381.9	0.0	Dec-92	258	307.4	129.8	0.0
Jan-93	344	192.5	77.3	0.0	Jan-93	111	282.2	365.3	0.0	Jan-93	221	295.1	148.0	0.0
Feb-93	241	217.9	91.9	0.0	Feb-93	110	273.5	348.5	0.0	Feb-93	381	134.3	71.1	0.0
Mar-93	306	207.9	131.4	0.0	Mar-93	183	239.5	364.5	0.0	Mar-93	384	173.3	99.8	0.0
Apr-93	311	218.4	160.5	0.0	Apr-93	223	216.1	431.3	0.0	Apr-93	300	227.8	114.1	0.0
May-93	313	237.6	189.7	0.0	May-93	312	174.9	456.2	0.0	May-93	388	183.5	115.2	0.0
Jun-93	344	218.4	150.8	0.0	Jun-93	303	158.3	430.4	0.0	Jun-93	402	171.3	114.4	0.0
Jul-93	337	211.8	142.0	0.0	Jul-93	264	139.3	509.2	0.0	Jul-93	351	182.7	126.7	0.0
Aug-93	318	207.9	139.6	0.0	Aug-93	179	153.6	453.0	0.0	Aug-93	372	175.9	121.4	0.0
Sep-93	292	210.0	150.8	0.0	Sep-93	164	149.1	469.6	0.0	Sep-93	362	173.5	120.5	0.0
Oct-93	238	219.7	212.6	0.0	Oct-93	117	151.8	404.8	0.0	Oct-93	381	179.2	159.4	0.0
Nov-93	308	210.1	226.8	0.0	Nov-93	126	169.5	440.1	0.0	Nov-93	357	179.5	164.9	0.0
Dec-93	306	207.9	226.1	0.0	Dec-93	160	144.2	463.2	0.0	Dec-93	357	178.4	162.5	0.0
Jan-94	310	211.1	222.6	0.0	Jan-94	177	152.9	502.5	0.0	Jan-94	402	163.9	149.2	0.0
Feb-94	276	211.1	287.0	0.0	Feb-94	167	150.5	414.2	0.0	Feb-94	362	161.9	161.7	0.0
Mar-94	312	207.1	253.4	0.0	Mar-94	189	121.6	465.6	0.0	Mar-94	330	196.3	176.3	0.0
Apr-94	308	209.5	248.4	0.0	Apr-94	192	113.5	471.6	0.0	Apr-94	362	171.7	163.6	0.0
May-94	276	202.8	289.8	0.0	May-94	233	118.7	469.8	0.0	May-94	396	169.7	165.4	0.0
Jun-94	294	209.3	296.7	0.0	Jun-94	163	124.7	482.9	0.0	Jun-94	404	156.6	148.9	0.0
Jul-94	326	158.3	285.3	0.0	Jul-94	150	121.8	453.8	0.0	Jul-94	377	165.4	181.2	0.0
Aug-94	271	185.9	380.4	0.0	Aug-94	133	140.4	406.7	0.0	Aug-94	392	163.8	184.9	0.0
Sep-94	333	175.2	372.7	0.0	Sep-94	127	133.6	398.4	0.0	Sep-94	385	163.2	196.7	0.0

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Table 4.1: Production History (Continued)

	Well	08-18-37-7W5				Well	16-08-37-7W5				Well	14-09-37-7W5		
	Battery	08-18-37-7W5		SATELLITE		Battery	08-18-37-7W5		SATELLITE		Battery	14-09-37-7W5		SINGLE
	Casing	Depth (ft)	Dia (in)	Wt (lb/ft^3)		Casing	Depth (ft)	Dia (in)	Wt (lb/ft^3)		Casing	Depth (ft)	Dia (in)	Wt (lb/ft^3)
	Surface	1353.7	9.6	3.35		Surface	1120.4	8.6	2.23		Surface	1482.9	9.6	3.35
	Prod	8776.2	5.5	2.23		Prod	8684.4	5.5	2.23		Prod	11154.9	7.0	2.23
Date	Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d	Date	Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d	Date	Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d
Oct-87					Oct-87					Oct-87				
Nov-87					Nov-87					Nov-87				
Dec-87					Dec-87					Dec-87				
Jan-88					Jan-88					Jan-88				
Feb-88					Feb-88					Feb-88				
Mar-88					Mar-88					Mar-88				
Apr-88					Apr-88					Apr-88				
May-88					May-88					May-88				
Jun-88					Jun-88					Jun-88				
Jul-88					Jul-88					Jul-88				
Aug-88					Aug-88					Aug-88				
Sep-88					Sep-88					Sep-88				
Oct-88					Oct-88					Oct-88				
Nov-88					Nov-88					Nov-88				
Dec-88					Dec-88					Dec-88				
Jan-89					Jan-89					Jan-89				
Feb-89					Feb-89					Feb-89				
Mar-89					Mar-89					Mar-89				
Apr-89					Apr-89					Apr-89				
May-89					May-89					May-89				
Jun-89					Jun-89					Jun-89				
Jul-89					Jul-89					Jul-89				
Aug-89					Aug-89					Aug-89				
Sep-89					Sep-89					Sep-89				
Oct-89					Oct-89					Oct-89				
Nov-89					Nov-89					Nov-89				
Dec-89					Dec-89					Dec-89				
Jan-90					Jan-90					Jan-90				
Feb-90					Feb-90					Feb-90				
Mar-90					Mar-90					Mar-90				
Apr-90					Apr-90					Apr-90				
May-90					May-90					May-90				
Jun-90					Jun-90					Jun-90				
Jul-90					Jul-90					Jul-90				
Aug-90					Aug-90					Aug-90				
Sep-90					Sep-90					Sep-90				
Oct-90					Oct-90					Oct-90				
Nov-90					Nov-90					Nov-90				
Dec-90					Dec-90					Dec-90				
Jan-91					Jan-91					Jan-91				
Feb-91					Feb-91					Feb-91				
Mar-91					Mar-91					Mar-91				
Apr-91					Apr-91					Apr-91				
May-91					May-91					May-91				
Jun-91					Jun-91					Jun-91				
Jul-91					Jul-91					Jul-91				
Aug-91					Aug-91					Aug-91				
Sep-91					Sep-91					Sep-91				
Oct-91					Oct-91					Oct-91				
Nov-91					Nov-91					Nov-91				
Dec-91					Dec-91					Dec-91				
Jan-92					Jan-92					Jan-92				
Feb-92					Feb-92					Feb-92				
Mar-92	93	130.8	299.5	0.0	Mar-92					Mar-92				
Apr-92					Apr-92					Apr-92				
May-92					May-92					May-92				
Jun-92					Jun-92					Jun-92				
Jul-92	738	110.7	123.2	0.0	Jul-92					Jul-92				
Aug-92	720	101.7	134.2	0.0	Aug-92	24			3.8	Aug-92				
Sep-92					Sep-92	483	203.5	457.5	0.0	Sep-92				
Oct-92	617	75.2	57.6	0.0	Oct-92	334	271.9	296.1	0.0	Oct-92				
Nov-92	720	35.8	19.9	0.0	Nov-92	382	236.1	264.3	0.0	Nov-92				
Dec-92	164	50.6	57.1	0.0	Dec-92	363	231.4	204.9	0.0	Dec-92				
Jan-93	493	120.7	99.3	0.0	Jan-93	262	239.6	268.5	0.0	Jan-93				
Feb-93	538	110.0	85.3	0.0	Feb-93	337	184.4	253.5	0.0	Feb-93	487	91.2	124.9	0.0
Mar-93	579	123.5	110.9	0.0	Mar-93	250	250.5	256.2	0.0	Mar-93	648	54.9	128.1	0.0
Apr-93	516	130.3	96.9	0.0	Apr-93	220	264.8	316.4	0.0	Apr-93	720	43.4	104.4	0.0
May-93	580	122.5	110.6	0.0	May-93	167	355.5	315.2	0.0	May-93	744	38.8	83.4	0.0
Jun-93	474	119.6	105.7	0.0	Jun-93	266	229.1	278.9	0.0	Jun-93	720	37.0	80.9	0.0
Jul-93	570	121.5	120.3	0.0	Jul-93	246	249.6	292.6	0.0	Jul-93	744	35.7	75.2	0.0
Aug-93	578	118.5	106.7	0.0	Aug-93	291	226.1	271.1	0.0	Aug-93	744	35.1	82.0	0.0
Sep-93	588	110.7	101.7	0.0	Sep-93	213	182.2	270.0	0.0	Sep-93	672	31.7	92.6	0.0
Oct-93	624	110.4	99.2	0.0	Oct-93	309	197.0	304.4	0.0	Oct-93	744	28.9	102.6	0.0
Nov-93	487	107.1	103.9	0.0	Nov-93	261	226.1	355.4	0.0	Nov-93	720	27.2	116.1	0.0
Dec-93	474	135.9	131.2	0.0	Dec-93	744	63.8	130.4	0.0	Dec-93	744	26.7	128.5	0.0
Jan-94	463	140.4	134.1	0.0	Jan-94	193	230.1	399.5	0.0	Jan-94	720	27.5	151.2	0.0
Feb-94	465	127.0	142.9	0.0	Feb-94	191	207.6	384.4	0.0	Feb-94	568	24.2	135.9	0.0
Mar-94	582	112.0	127.8	0.0	Mar-94	216	157.2	350.2	0.0	Mar-94	744	22.8	144.1	0.0
Apr-94	537	119.6	132.0	0.0	Apr-94	192	226.8	458.3	0.0	Apr-94	698	21.1	146.9	0.0
May-94	600	120.0	162.3	0.0	May-94	192	183.3	386.0	0.0	May-94	744	21.2	157.6	0.0
Jun-94	607	108.9	153.4	0.0	Jun-94	231	118.6	476.8	0.0	Jun-94	480	38.6	194.5	0.0
Jul-94	655	100.6	168.7	0.0	Jul-94	264	134.5	668.9	0.0	Jul-94	288	42.7	197.3	0.0
Aug-94	546	95.9	193.0	0.0	Aug-94	480	52.0	594.4	0.0	Aug-94	264	36.0	133.5	0.0
Sep-94	474	94.2	200.0	0.0	Sep-94	112	160.1	455.6	0.0	Sep-94	312	24.6	187.4	0.0

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

Table 4.1: Production History (Continued)

	Well	08-17-37-7W5		
	Battery	08-18-37-7W5		SATELLITE
	Casing	Depth (ft)	Dia (in)	Wt (lb/ft³)
	Surface	1151.6	8.6	2.23
	Prod	8667.3	5.5	2.23
Date	Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d
Oct-87				
Nov-87				
Dec-87				
Jan-88				
Feb-88				
Mar-88				
Apr-88				
May-88				
Jun-88				
Jul-88				
Aug-88				
Sep-88				
Oct-88				
Nov-88				
Dec-88				
Jan-89				
Feb-89				
Mar-89				
Apr-89				
May-89				
Jun-89				
Jul-89				
Aug-89				
Sep-89				
Oct-89				
Nov-89				
Dec-89				
Jan-90				
Feb-90				
Mar-90				
Apr-90				
May-90				
Jun-90				
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Oct-90				
Nov-90				
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Jan-91				
Feb-91				
Mar-91				
Apr-91				
May-91				
Jun-91				
Jul-91				
Aug-91				
Sep-91				
Oct-91				
Nov-91				
Dec-91				
Jan-92				
Feb-92				
Mar-92				
Apr-92				
May-92				
Jun-92				
Jul-92				
Aug-92				
Sep-92				
Oct-92				
Nov-92				
Dec-92				
Jan-93				
Feb-93				
Mar-93	12	561.1	631.8	16.4
Apr-93	472	499.1	403.2	0.0
May-93				
Jun-93	238	524.7	463.5	0.0
Jul-93	118	538.3	476.5	0.0
Aug-93	119	527.0	468.2	0.0
Sep-93	116	526.1	466.3	0.0
Oct-93	120	526.0	501.2	0.0
Nov-93	126	488.7	524.0	0.0
Dec-93	271	235.1	259.3	0.0
Jan-94	290	222.7	288.5	0.0
Feb-94	324	184.9	325.8	0.0
Mar-94	401	161.6	347.8	0.0
Apr-94	377	148.1	362.0	0.0
May-94	286	151.3	371.4	0.0
Jun-94	236	149.4	377.2	0.0
Jul-94	211	148.8	384.3	0.0
Aug-94	192	155.6	393.1	0.0
Sep-94	167	161.0	387.2	0.0

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

	Well	14-07-37-7W5		
	Battery	08-18-37-7W5		SATELLITE
	Casing	Depth (ft)	Dia (in)	Wt (lb/ft³)
	Surface	1177.8	8.6	2.23
	Prod	8822.2	5.5	2.23
Date	Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d
Oct-87				
Nov-87				
Dec-87				
Jan-88				
Feb-88				
Mar-88				
Apr-88				
May-88				
Jun-88				
Jul-88				
Aug-88				
Sep-88				
Oct-88				
Nov-88				
Dec-88				
Jan-89				
Feb-89				
Mar-89				
Apr-89				
May-89				
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Nov-91				
Dec-91				
Jan-92				
Feb-92				
Mar-92				
Apr-92				
May-92				
Jun-92				
Jul-92				
Aug-92				
Sep-92				
Oct-92				
Nov-92				
Dec-92				
Jan-93				
Feb-93				
Mar-93				
Apr-93				
May-93				
Jun-93	72	191.2		0.0
Jul-93	465	389.0	428.0	0.0
Aug-93	474	380.5	467.1	0.0
Sep-93				
Oct-93				
Nov-93	189	355.4	515.6	0.0
Dec-93	227	281.5	543.0	0.0
Jan-94	307	216.2	374.3	0.0
Feb-94	293	196.6	389.9	0.0
Mar-94	206	190.0	381.7	0.0
Apr-94	234	180.1	383.0	0.0
May-94	198	174.4	423.8	0.0
Jun-94	222	161.1	432.9	0.0
Jul-94	217	160.2	407.1	0.0
Aug-94	193	154.7	406.9	0.0
Sep-94	169	143.7	411.3	0.0

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

	Well	14-12-37-8W5		
	Battery	06-13-37-8W5		SATELLITE
	Casing	Depth (ft)	Dia (in)	Wt (lb/ft³)
	Surface	1349.1	9.6	3.35
	Prod	9012.1	5.5	2.23
Date	Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d
Oct-87				
Nov-87				
Dec-87				
Jan-88				
Feb-88				
Mar-88				
Apr-88				
May-88				
Jun-88				
Jul-88				
Aug-88				
Sep-88				
Oct-88				
Nov-88				
Dec-88				
Jan-89				
Feb-89				
Mar-89				
Apr-89				
May-89				
Jun-89				
Jul-89				
Aug-89				
Sep-89				
Oct-89				
Nov-89				
Dec-89				
Jan-90				
Feb-90				
Mar-90				
Apr-90				
May-90				
Jun-90				
Jul-90				
Aug-90				
Sep-90				
Oct-90				
Nov-90				
Dec-90				
Jan-91				
Feb-91				
Mar-91				
Apr-91				
May-91				
Jun-91				
Jul-91				
Aug-91				
Sep-91				
Oct-91				
Nov-91				
Dec-91				
Jan-92				
Feb-92				
Mar-92				
Apr-92				
May-92				
Jun-92				
Jul-92				
Aug-92				
Sep-92				
Oct-92				
Nov-92				
Dec-92				
Jan-93				
Feb-93				
Mar-93				
Apr-93				
May-93				
Jun-93				
Jul-93				
Aug-93				
Sep-93	333	303.5	181.6	5.3
Oct-93	744	132.6	86.6	1.3
Nov-93	597	146.9	102.2	2.8
Dec-93	528	130.5	98.2	0.0
Jan-94	528	134.8	103.1	0.0
Feb-94	437	132.0	95.7	0.0
Mar-94	541	126.2	92.4	0.0
Apr-94	499	122.9	82.6	0.0
May-94	575	117.9	85.0	0.0
Jun-94	577	114.6	83.0	0.0
Jul-94	587	111.7	74.0	0.0
Aug-94	610	103.3	74.6	0.0
Sep-94	413	83.4	64.6	0.0

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

Table 4.1: Production History (Continued)

	Well	16-12-37-8W5				Well	08-07-37-7W5							
	Battery	06-13-37-8W5		SATELLITE		Battery	08-18-37-7W5		SATELLITE					
	Casing	Depth (ft)	Dia (in)	Wt (lb/ft^3)		Casing	Depth (ft)	Dia (in)	Wt (lb/ft^3)					
	Surface	1299.2	9.6	3.35		Surface	1079.4	8.6	2.23	Cumulative Pool Production				
	Prod	8933.7	5.5	2.23		Prod	8864.8	5.5	2.23					
Date	Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d	Date	Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d	Date	Oil MSTB	Gas MMscf	Water MSTB	Wells Producing
Oct-87					Oct-87					Oct-87				
Nov-87					Nov-87					Nov-87	0.8	0.7	0.0	1
Dec-87					Dec-87					Dec-87	1.2	1.9	0.0	1
Jan-88					Jan-88					Jan-88	1.7	2.2	0.0	1
Feb-88					Feb-88					Feb-88	2.4	4.1	0.0	1
Mar-88					Mar-88					Mar-88	3.0	5.3	0.0	1
Apr-88					Apr-88					Apr-88	3.5	6.0	0.0	1
May-88					May-88					May-88	4.1	6.9	0.0	1
Jun-88					Jun-88					Jun-88	4.6	7.9	0.0	1
Jul-88					Jul-88					Jul-88	5.2	9.1	0.0	1
Aug-88					Aug-88					Aug-88	5.7	10.2	0.0	1
Sep-88					Sep-88					Sep-88	6.2	11.2	0.0	1
Oct-88					Oct-88					Oct-88	6.8	12.2	0.0	1
Nov-88					Nov-88					Nov-88	7.3	13.2	0.0	1
Dec-88					Dec-88					Dec-88	7.8	13.9	0.0	1
Jan-89					Jan-89					Jan-89	8.4	14.8	0.0	1
Feb-89					Feb-89					Feb-89	8.9	15.6	0.0	1
Mar-89					Mar-89					Mar-89	12.0	24.5	0.0	2
Apr-89					Apr-89					Apr-89	14.6	34.9	0.0	2
May-89					May-89					May-89	16.8	45.7	0.0	2
Jun-89					Jun-89					Jun-89	18.8	55.4	0.0	2
Jul-89					Jul-89					Jul-89	19.7	58.9	0.0	2
Aug-89					Aug-89					Aug-89	20.6	63.5	0.0	2
Sep-89					Sep-89					Sep-89	21.6	67.6	0.0	2
Oct-89					Oct-89					Oct-89	22.4	71.1	0.0	2
Nov-89					Nov-89					Nov-89	23.3	73.5	0.0	2
Dec-89					Dec-89					Dec-89	24.1	76.2	0.0	2
Jan-90					Jan-90					Jan-90	25.1	80.1	0.0	2
Feb-90					Feb-90					Feb-90	26.0	83.8	0.0	2
Mar-90					Mar-90					Mar-90	29.2	88.8	0.1	3
Apr-90					Apr-90					Apr-90	30.8	92.8	0.1	3
May-90					May-90					May-90	40.2	102.9	0.1	3
Jun-90					Jun-90					Jun-90	47.3	112.2	0.1	3
Jul-90					Jul-90					Jul-90	49.0	116.1	0.1	3
Aug-90					Aug-90					Aug-90	56.6	127.1	0.1	4
Sep-90					Sep-90					Sep-90	63.9	135.5	0.1	4
Oct-90					Oct-90					Oct-90	76.0	147.3	0.3	5
Nov-90					Nov-90					Nov-90	88.2	158.7	0.3	5
Dec-90					Dec-90					Dec-90	102.5	174.6	0.3	5
Jan-91					Jan-91					Jan-91	108.9	181.4	0.3	4
Feb-91					Feb-91					Feb-91	122.1	193.2	0.3	6
Mar-91					Mar-91					Mar-91	136.3	206.7	0.3	6
Apr-91					Apr-91					Apr-91	150.4	220.8	0.3	6
May-91					May-91					May-91	159.7	230.6	0.3	5
Jun-91					Jun-91					Jun-91	172.0	243.0	0.3	6
Jul-91					Jul-91					Jul-91	184.4	255.5	0.3	6
Aug-91					Aug-91					Aug-91	196.2	266.9	0.3	6
Sep-91					Sep-91					Sep-91	208.3	279.1	0.3	6
Oct-91					Oct-91					Oct-91	220.5	291.5	0.3	6
Nov-91					Nov-91					Nov-91	232.6	303.6	0.3	6
Dec-91					Dec-91					Dec-91	244.6	316.1	0.4	6
Jan-92					Jan-92					Jan-92	257.0	329.3	0.4	6
Feb-92					Feb-92					Feb-92	268.1	341.4	0.4	6
Mar-92					Mar-92					Mar-92	281.1	357.2	0.4	7
Apr-92					Apr-92					Apr-92	293.2	371.7	0.4	6
May-92					May-92					May-92	305.4	386.4	0.4	6
Jun-92					Jun-92					Jun-92	316.8	399.8	0.4	6
Jul-92					Jul-92					Jul-92	331.9	416.9	0.4	7
Aug-92					Aug-92					Aug-92	346.7	434.0	0.4	8
Sep-92					Sep-92					Sep-92	361.8	456.1	0.4	7
Oct-92					Oct-92					Oct-92	379.5	476.5	0.5	8
Nov-92					Nov-92					Nov-92	396.0	495.0	0.5	8
Dec-92					Dec-92					Dec-92	412.5	510.0	0.5	8
Jan-93					Jan-93					Jan-93	428.4	524.0	0.5	8
Feb-93					Feb-93					Feb-93	444.8	541.4	0.5	9
Mar-93					Mar-93					Mar-93	463.6	561.9	0.5	10
Apr-93					Apr-93					Apr-93	492.0	592.1	0.5	10
May-93					May-93					May-93	510.7	616.6	0.5	9
Jun-93					Jun-93					Jun-93	534.9	644.3	0.5	11
Jul-93					Jul-93					Jul-93	562.2	678.3	0.5	11
Aug-93					Aug-93					Aug-93	589.3	711.6	0.5	11
Sep-93					Sep-93					Sep-93	611.7	736.6	0.5	11
Oct-93	185	593.1	67.2	3.6	Oct-93					Oct-93	639.9	763.4	0.6	12
Nov-93	624	421.0	336.7	0.0	Nov-93					Nov-93	674.8	804.5	0.7	13
Dec-93					Dec-93					Dec-93	697.4	839.8	0.7	12
Jan-94					Jan-94					Jan-94	720.4	877.6	0.7	12
Feb-94	215	401.6	386.3	0.0	Feb-94					Feb-94	744.2	915.5	0.7	13
Mar-94	168	379.3	404.6	0.0	Mar-94					Mar-94	767.3	956.0	0.7	13
Apr-94	120	397.4	396.8	0.0	Apr-94	24	562.9	408.2	0.0	Apr-94	789.4	995.0	0.7	14
May-94	144	407.8	518.2	0.0	May-94	158	370.5	259.3	0.0	May-94	813.4	1040.1	0.7	14
Jun-94	120	396.5	379.1	0.4	Jun-94	560	305.6	212.4	0.0	Jun-94	840.4	1083.7	0.7	14
Jul-94	120	451.6	584.9	0.0	Jul-94	576	239.3	233.1	0.0	Jul-94	865.7	1132.9	0.7	14
Aug-94	168	382.9	637.4	0.0	Aug-94	240	271.2	213.3	0.0	Aug-94	886.6	1179.4	0.7	14
Sep-94	168	379.8	709.4	0.1	Sep-94	264	242.3	221.0	0.0	Sep-94	905.6	1218.0	0.7	14

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

Table 4.1: Production History (Continued)

Date	Well	16-9-37-7W5			Date	Well	6-15-37-7W5			Date	Well	8-13-37-8W5		
	Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d		Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d		Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d
Oct-87					Oct-87					Oct-87				
Nov-87	477	38.2	58.8	0.0	Nov-87					Nov-87				
Dec-87	528	21.2	45.2	0.0	Dec-87					Dec-87				
Jan-88	288	36.9	79.5	0.0	Jan-88					Jan-88				
Feb-88	696	25.9	54.7	0.0	Feb-88					Feb-88				
Mar-88	744	18.1	42.6	0.0	Mar-88					Mar-88				
Apr-88	480	25.1	56.7	0.0	Apr-88					Apr-88				
May-88	579	25.2	49.5	0.0	May-88					May-88				
Jun-88	705	15.8	27.1	0.0	Jun-88					Jun-88				
Jul-88	722	20.0	31.9	0.0	Jul-88					Jul-88				
Aug-88	739	18.1	29.0	0.0	Aug-88					Aug-88				
Sep-88	588	20.4	32.8	0.0	Sep-88					Sep-88				
Oct-88	728	18.7	27.8	0.0	Oct-88					Oct-88				
Nov-88	720	17.3	26.1	0.0	Nov-88					Nov-88				
Dec-88	568	22.5	35.5	0.0	Dec-88					Dec-88				
Jan-89	740	18.8	28.0	0.0	Jan-89					Jan-89				
Feb-89	648	17.8	27.7	0.0	Feb-89					Feb-89				
Mar-89	528	19.6	30.5	0.0	Mar-89	636	102.6	107.0	0.0	Mar-89				
Apr-89	432	28.4	40.0	0.0	Apr-89	676	71.6	75.4	0.0	Apr-89				
May-89	552	25.2	35.9	0.0	May-89	735	53.6	56.5	0.0	May-89				
Jun-89	711	18.3	26.6	0.0	Jun-89	720	49.2	52.4	0.0	Jun-89				
Jul-89	744	17.4	26.6	0.0	Jul-89	185	49.4	53.8	0.0	Jul-89				
Aug-89	744	15.9	24.3	0.0	Aug-89	288	33.3	33.0	0.0	Aug-89				
Sep-89	720	20.1	31.2	0.0	Sep-89	240	42.5	41.2	0.0	Sep-89				
Oct-89	525	16.9	27.7	0.0	Oct-89	176	58.7	56.9	0.0	Oct-89				
Nov-89	720	17.5	23.7	0.0	Nov-89	108	65.0	63.0	0.0	Nov-89				
Dec-89	744	15.8	22.3	0.0	Dec-89	139	63.3	61.3	0.0	Dec-89				
Jan-90	744	15.0	20.9	0.0	Jan-90	173	67.3	65.2	0.0	Jan-90				
Feb-90	672	16.1	22.3	0.0	Feb-90	189	64.0	61.9	0.0	Feb-90				
Mar-90	744	16.2	22.9	0.0	Mar-90	155	86.7	83.7	0.0	Mar-90	125	408.6	364.6	0.0
Apr-90	720	14.8	20.9	0.0	Apr-90	142	71.0	68.4	0.0	Apr-90	45	390.5	348.5	0.0
May-90	744	14.7	20.2	0.0	May-90	144	83.3	80.5	0.0	May-90	575	352.0	314.1	0.0
Jun-90	720	15.0	20.4	0.0	Jun-90	234	57.2	55.5	0.0	Jun-90	400	367.1	327.6	0.0
Jul-90	432	18.7	26.1	0.0	Jul-90	160	72.9	74.7	0.0	Jul-90	54	359.8	321.1	0.0
Aug-90	744	18.7	23.1	0.0	Aug-90	282	53.4	60.2	0.0	Aug-90	168	357.2	318.7	0.0
Sep-90	720	16.7	23.9	0.0	Sep-90	143	73.2	87.7	0.0	Sep-90	189	361.6	322.7	0.0
Oct-90	720	16.3	24.3	0.0	Oct-90	168	79.3	101.8	0.0	Oct-90	188	364.2	325.0	0.0
Nov-90	720	18.0	27.3	0.0	Nov-90	117	70.9	94.6	0.0	Nov-90	204	343.4	306.3	0.0
Dec-90	639	17.4	27.6	0.0	Dec-90	120	97.5	132.3	0.0	Dec-90	192	355.8	317.3	0.0
Jan-91	744	18.5	27.8	0.0	Jan-91	142	99.1	137.4	0.0	Jan-91	192	352.3	313.2	0.0
Feb-91	672	18.2	29.2	0.0	Feb-91	166	84.1	116.9	0.0	Feb-91	172	354.5	314.3	0.0
Mar-91	710	16.3	26.4	0.0	Mar-91	262	79.6	116.5	0.0	Mar-91	163	342.1	301.7	0.0
Apr-91	615	17.5	27.3	0.0	Apr-91	286	73.0	113.4	0.0	Apr-91	192	339.1	296.6	0.0
May-91	744	16.7	24.4	0.0	May-91	264	72.6	118.2	0.0	May-91	201	341.4	295.4	0.0
Jun-91	720	15.9	24.0	0.0	Jun-91	288	74.9	128.0	0.0	Jun-91	192	348.1	297.9	0.0
Jul-91	744	15.5	23.6	0.0	Jul-91	264	74.0	132.4	0.0	Jul-91	207	334.3	283.5	0.0
Aug-91	744	14.2	21.4	0.0	Aug-91	240	76.7	141.2	0.0	Aug-91	192	359.7	302.7	0.0
Sep-91	720	14.2	21.0	0.0	Sep-91	260	73.0	138.6	0.0	Sep-91	209	323.0	269.3	0.0
Oct-91	744	12.8	18.6	0.0	Oct-91	240	67.4	131.8	0.0	Oct-91	207	330.7	274.2	0.0
Nov-91	720	13.0	18.5	0.0	Nov-91	334	75.9	157.2	0.0	Nov-91	187	362.0	298.3	0.0
Dec-91	432	12.4	17.7	0.0	Dec-91	336	68.3	151.2	0.0	Dec-91	188	366.1	299.3	0.0
Jan-92	744	12.0	14.3	0.0	Jan-92	291	69.3	159.6	0.0	Jan-92	192	354.7	287.9	0.0
Feb-92	696	20.3	29.6	0.0	Feb-92	265	72.6	173.9	0.0	Feb-92	144	341.0	275.3	0.0
Mar-92	744	20.1	37.6	0.0	Mar-92	359	60.6	153.5	0.0	Mar-92	208	325.1	261.3	0.0
Apr-92	720	19.2	40.2	0.0	Apr-92	336	56.7	148.0	0.0	Apr-92	192	343.1	275.9	0.0
May-92	744	19.1	41.7	0.0	May-92	480	51.8	141.1	0.0	May-92	187	360.7	288.3	0.0
Jun-92	720	18.5	40.8	0.0	Jun-92	466	47.0	135.7	0.0	Jun-92	176	375.8	298.3	0.0
Jul-92	744	18.5	40.3	0.0	Jul-92	312	55.8	167.0	0.0	Jul-92	181	375.0	295.6	0.0
Aug-92	744	17.7	37.7	0.0	Aug-92	265	66.0	200.2	0.0	Aug-92	185	364.7	286.1	0.0
Sep-92	720	16.9	34.8	0.0	Sep-92	240	71.7	222.3	0.0	Sep-92	178	371.7	290.2	0.0
Oct-92	744	16.2	32.1	0.0	Oct-92	205	71.5	225.1	0.0	Oct-92	182	374.4	290.8	0.0
Nov-92	720	16.3	31.4	0.0	Nov-92	166	83.8	264.6	0.0	Nov-92	240	273.0	211.1	0.0
Dec-92	744	15.2	28.7	0.0	Dec-92	208	81.2	264.7	0.0	Dec-92	335	192.0	148.5	0.0
Jan-93	744	15.1	28.0	0.0	Jan-93	290	70.9	244.9	0.0	Jan-93	273	241.8	199.1	0.0
Feb-93	672	14.7	27.2	0.0	Feb-93	334	60.2	214.5	0.0	Feb-93	322	192.5	177.2	0.0
Mar-93	744	14.4	26.7	0.0	Mar-93					Mar-93	364	188.8	204.8	0.0
Apr-93	720	13.0	24.0	0.0	Apr-93					Apr-93	375	172.5	176.8	0.0
May-93	744	9.6	16.9	0.0	May-93					May-93	456	165.0	204.2	0.0
Jun-93	720	11.9	20.3	0.0	Jun-93					Jun-93	401	169.6	222.3	0.0
Jul-93	744	12.0	21.3	0.0	Jul-93					Jul-93	398	154.4	207.0	0.0
Aug-93	666	11.1	20.4	0.0	Aug-93					Aug-93	257	265.6	400.9	0.0
Sep-93	720	9.2	16.5	0.0	Sep-93					Sep-93	228	284.2	455.2	0.0
Oct-93	576	7.2	12.7	0.0	Oct-93					Oct-93	271	252.0	407.8	0.0
Nov-93	720	5.9	9.5	0.0	Nov-93					Nov-93	257	248.3	385.2	0.0
Dec-93	744	8.1	13.4	0.0	Dec-93					Dec-93	312	173.5	302.2	0.0
Jan-94	744	7.3	12.7	0.0	Jan-94					Jan-94	372	148.1	266.9	0.0
Feb-94	607	8.0	14.5	0.0	Feb-94					Feb-94	241	151.8	288.4	0.0
Mar-94	724	7.3	13.5	0.0	Mar-94					Mar-94	270	134.6	279.6	0.0
Apr-94	720	6.8	12.9	0.0	Apr-94					Apr-94	198	132.0	286.8	0.0
May-94	744	6.4	12.4	0.0	May-94					May-94	239	109.3	234.9	0.0
Jun-94	720	6.5	12.8	0.0	Jun-94					Jun-94	128	177.1	367.4	0.0
Jul-94	528	6.0	12.0	0.0	Jul-94					Jul-94	239	92.6	187.4	0.0
Aug-94	504	9.2	18.3	0.0	Aug-94					Aug-94	120	104.2	224.6	0.0
Sep-94					Sep-94					Sep-94	164	105.0	239.7	0.0

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

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GOR = 1.129 Mscf/STB

Table 4.2: Chedderville Viking "A" Production Match (Oct-94)

Date	Well	6-13-37-8W5			Date	Well	6-16-37-7W5			Date	Well	8-14-37-8W5		
	Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d		Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d		Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d
Oct-87					Oct-87					Oct-87				
Nov-87					Nov-87					Nov-87				
Dec-87					Dec-87					Dec-87				
Jan-88					Jan-88					Jan-88				
Feb-88					Feb-88					Feb-88				
Mar-88					Mar-88					Mar-88				
Apr-88					Apr-88					Apr-88				
May-88					May-88					May-88				
Jun-88					Jun-88					Jun-88				
Jul-88					Jul-88					Jul-88				
Aug-88					Aug-88					Aug-88				
Sep-88					Sep-88					Sep-88				
Oct-88					Oct-88					Oct-88				
Nov-88					Nov-88					Nov-88				
Dec-88					Dec-88					Dec-88				
Jan-89					Jan-89					Jan-89				
Feb-89					Feb-89					Feb-89				
Mar-89					Mar-89					Mar-89				
Apr-89					Apr-89					Apr-89				
May-89					May-89					May-89				
Jun-89					Jun-89					Jun-89				
Jul-89					Jul-89					Jul-89				
Aug-89					Aug-89					Aug-89				
Sep-89					Sep-89					Sep-89				
Oct-89					Oct-89					Oct-89				
Nov-89					Nov-89					Nov-89				
Dec-89					Dec-89					Dec-89				
Jan-90					Jan-90					Jan-90				
Feb-90					Feb-90					Feb-90				
Mar-90					Mar-90					Mar-90				
Apr-90					Apr-90					Apr-90				
May-90					May-90					May-90				
Jun-90					Jun-90					Jun-90				
Jul-90					Jul-90					Jul-90				
Aug-90	744	127.7	111.9	0.0	Aug-90					Aug-90				
Sep-90	528	160.4	140.6	0.0	Sep-90					Sep-90				
Oct-90	744	222.2	194.8	0.0	Oct-90	63	491.1	430.5	0.0	Oct-90				
Nov-90	120	173.6	152.2	0.0	Nov-90	621	290.1	254.3	0.0	Nov-90				
Dec-90	672	122.3	107.2	0.0	Dec-90	583	291.6	255.6	0.0	Dec-90				
Jan-91	336	173.0	151.6	0.0	Jan-91					Jan-91				
Feb-91	408	138.4	121.3	0.0	Feb-91	213	268.3	235.2	0.0	Feb-91	600	192.3	156.5	0.0
Mar-91	288	224.5	196.3	0.0	Mar-91	234	270.7	237.3	0.0	Mar-91	744	167.5	136.3	0.0
Apr-91	312	226.6	196.8	0.0	Apr-91	244	254.8	223.3	0.0	Apr-91	720	153.6	125.0	0.0
May-91	264	222.4	192.1	0.0	May-91	236	266.4	233.5	0.0	May-91				
Jun-91	312	225.0	192.3	0.0	Jun-91	231	266.1	233.2	0.0	Jun-91	384	168.5	137.1	0.0
Jul-91	288	235.0	199.7	0.0	Jul-91	238	262.9	230.4	0.0	Jul-91	744	88.6	72.1	0.0
Aug-91	240	249.4	210.3	0.0	Aug-91	264	237.9	208.5	0.0	Aug-91	264	241.2	196.3	0.0
Sep-91	312	212.5	177.3	0.0	Sep-91	262	237.5	208.3	0.0	Sep-91	336	195.2	158.9	0.0
Oct-91	288	235.7	195.4	0.0	Oct-91	264	238.6	209.0	0.0	Oct-91	312	214.4	174.5	0.0
Nov-91	264	249.7	205.4	0.0	Nov-91	237	257.7	225.2	0.0	Nov-91	288	211.4	172.0	0.0
Dec-91	240	280.4	228.9	0.0	Dec-91	262	237.7	207.1	0.0	Dec-91	240	258.6	209.9	0.0
Jan-92	240	295.9	239.4	0.0	Jan-92	261	239.5	208.2	0.0	Jan-92	240	272.6	219.9	0.0
Feb-92	216	274.2	219.9	0.0	Feb-92	266	236.1	204.9	0.0	Feb-92	216	286.8	229.3	0.0
Mar-92	240	288.3	229.9	0.0	Mar-92	285	220.8	192.3	0.0	Mar-92	264	243.4	193.7	0.0
Apr-92	264	249.1	198.5	0.0	Apr-92	245	251.0	220.8	0.0	Apr-92	240	271.7	216.2	0.0
May-92	288	234.1	185.6	0.0	May-92	237	223.2	196.0	0.0	May-92	240	268.5	212.2	0.0
Jun-92	264	248.6	196.3	0.0	Jun-92	178	239.5	211.5	0.0	Jun-92	240	273.1	214.4	0.0
Jul-92	504	132.1	104.1	0.0	Jul-92	193	251.1	229.7	0.0	Jul-92	312	208.8	163.5	0.0
Aug-92	480	140.3	110.6	0.0	Aug-92	215	237.2	306.9	0.0	Aug-92	504	129.1	101.1	0.0
Sep-92	264	245.2	192.3	0.0	Sep-92	210	246.2	498.1	0.0	Sep-92	312	170.6	133.5	0.0
Oct-92	336	200.8	156.8	0.0	Oct-92	289	207.2	503.9	0.0	Oct-92	288	228.7	178.5	0.0
Nov-92	408	163.9	128.0	0.0	Nov-92	360	154.7	363.3	0.0	Nov-92	288	229.8	178.9	0.0
Dec-92	334	230.3	178.8	0.0	Dec-92	240	225.7	472.2	0.0	Dec-92	258	307.4	237.6	0.0
Jan-93	344	192.5	149.3	0.0	Jan-93	111	282.2	521.1	0.0	Jan-93	221	295.1	227.0	0.0
Feb-93	241	217.9	168.7	0.0	Feb-93	110	273.5	486.2	0.0	Feb-93	381	134.3	104.0	0.0
Mar-93	306	207.9	160.1	0.0	Mar-93	183	239.5	507.3	0.0	Mar-93	384	173.3	133.9	0.0
Apr-93	311	218.4	168.1	0.0	Apr-93	223	216.1	528.0	0.0	Apr-93	300	227.8	175.7	0.0
May-93	313	237.6	182.7	0.0	May-93	312	174.9	445.0	0.0	May-93	388	183.5	141.6	0.0
Jun-93	344	218.4	168.7	0.0	Jun-93	303	158.3	387.1	0.0	Jun-93	402	171.3	132.3	0.0
Jul-93	337	211.8	170.9	0.0	Jul-93	264	139.3	337.2	0.0	Jul-93	351	182.7	140.9	0.0
Aug-93	318	207.9	183.6	0.0	Aug-93	179	153.6	366.9	0.0	Aug-93	372	175.9	135.4	0.0
Sep-93	292	210.0	195.1	0.0	Sep-93	154	149.1	356.0	0.0	Sep-93	362	173.5	134.7	0.0
Oct-93	238	219.7	203.9	0.0	Oct-93	117	151.8	380.9	0.0	Oct-93	381	179.2	146.7	0.0
Nov-93	308	210.1	210.0	0.0	Nov-93	126	169.5	410.5	0.0	Nov-93	357	179.5	151.9	0.0
Dec-93	306	207.9	218.8	0.0	Dec-93	160	144.2	382.1	0.0	Dec-93	357	178.4	152.4	0.0
Jan-94	310	211.1	210.4	0.0	Jan-94	177	152.9	441.7	0.0	Jan-94	402	163.9	139.9	0.0
Feb-94	276	211.1	250.9	0.0	Feb-94	167	150.5	495.3	0.0	Feb-94	362	161.9	138.3	0.0
Mar-94	312	207.1	268.8	0.0	Mar-94	189	121.6	446.7	0.0	Mar-94	330	196.3	173.3	0.0
Apr-94	308	209.4	287.1	0.0	Apr-94	192	113.5	445.7	0.0	Apr-94	362	171.7	147.1	0.0
May-94	276	202.8	251.6	0.0	May-94	233	118.7	472.6	0.0	May-94	396	169.7	132.2	0.0
Jun-94	294	209.3	247.3	0.0	Jun-94	163	124.7	475.2	0.0	Jun-94	404	156.5	118.0	0.0
Jul-94	326	158.3	225.4	0.0	Jul-94	150	121.8	452.6	0.0	Jul-94	377	165.4	141.7	0.0
Aug-94	271	185.9	306.3	0.0	Aug-94	133	140.4	556.9	0.0	Aug-94	392	163.8	154.2	0.0
Sep-94	333	175.2	294.5	0.0	Sep-94	127	133.6	566.2	0.0	Sep-94	385	163.2	156.0	0.0

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

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GOR = 1.129 Mscf/STB

Table 4.2: Production Match (Continued)

Date	Well	8-18-37-7W5			Date	Well	16-8-37-7W5			Date	Well	14-9-37-7W5		
	Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d		Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d		Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d
Oct-87					Oct-87					Oct-87				
Nov-87					Nov-87					Nov-87				
Dec-87					Dec-87					Dec-87				
Jan-88					Jan-88					Jan-88				
Feb-88					Feb-88					Feb-88				
Mar-88					Mar-88					Mar-88				
Apr-88					Apr-88					Apr-88				
May-88					May-88					May-88				
Jun-88					Jun-88					Jun-88				
Jul-88					Jul-88					Jul-88				
Aug-88					Aug-88					Aug-88				
Sep-88					Sep-88					Sep-88				
Oct-88					Oct-88					Oct-88				
Nov-88					Nov-88					Nov-88				
Dec-88					Dec-88					Dec-88				
Jan-89					Jan-89					Jan-89				
Feb-89					Feb-89					Feb-89				
Mar-89					Mar-89					Mar-89				
Apr-89					Apr-89					Apr-89				
May-89					May-89					May-89				
Jun-89					Jun-89					Jun-89				
Jul-89					Jul-89					Jul-89				
Aug-89					Aug-89					Aug-89				
Sep-89					Sep-89					Sep-89				
Oct-89					Oct-89					Oct-89				
Nov-89					Nov-89					Nov-89				
Dec-89					Dec-89					Dec-89				
Jan-90					Jan-90					Jan-90				
Feb-90					Feb-90					Feb-90				
Mar-90					Mar-90					Mar-90				
Apr-90					Apr-90					Apr-90				
May-90					May-90					May-90				
Jun-90					Jun-90					Jun-90				
Jul-90					Jul-90					Jul-90				
Aug-90					Aug-90					Aug-90				
Sep-90					Sep-90					Sep-90				
Oct-90					Oct-90					Oct-90				
Nov-90					Nov-90					Nov-90				
Dec-90					Dec-90					Dec-90				
Jan-91					Jan-91					Jan-91				
Feb-91					Feb-91					Feb-91				
Mar-91					Mar-91					Mar-91				
Apr-91					Apr-91					Apr-91				
May-91					May-91					May-91				
Jun-91					Jun-91					Jun-91				
Jul-91					Jul-91					Jul-91				
Aug-91					Aug-91					Aug-91				
Sep-91					Sep-91					Sep-91				
Oct-91					Oct-91					Oct-91				
Nov-91					Nov-91					Nov-91				
Dec-91					Dec-91					Dec-91				
Jan-92					Jan-92					Jan-92				
Feb-92					Feb-92					Feb-92				
Mar-92	93	130.8	110.5	0.0	Mar-92					Mar-92				
Apr-92					Apr-92					Apr-92				
May-92					May-92					May-92				
Jun-92					Jun-92					Jun-92				
Jul-92	738	110.7	92.7	0.0	Jul-92					Jul-92				
Aug-92	720	101.7	84.4	0.0	Aug-92					Aug-92				
Sep-92					Sep-92	483	203.5	253.1	0.0	Sep-92				
Oct-92	617	75.2	62.7	0.0	Oct-92	334	271.9	456.2	0.0	Oct-92				
Nov-92	720	35.8	29.8	0.0	Nov-92	382	236.1	384.1	0.0	Nov-92				
Dec-92	164	50.6	42.1	0.0	Dec-92	363	231.4	366.7	0.0	Dec-92				
Jan-93	493	120.7	99.4	0.0	Jan-93	262	239.6	339.1	0.0	Jan-93				
Feb-93	538	110.0	90.1	0.0	Feb-93	337	184.4	210.9	0.0	Feb-93	487	91.2	163.7	0.0
Mar-93	579	123.5	100.5	0.0	Mar-93	250	250.5	253.9	0.0	Mar-93	648	54.9	124.5	0.0
Apr-93	516	130.3	105.4	0.0	Apr-93	220	264.8	274.7	0.0	Apr-93	720	43.4	92.1	0.0
May-93	580	122.5	98.3	0.0	May-93	167	355.5	402.2	0.0	May-93	744	38.8	77.1	0.0
Jun-93	474	119.6	95.6	0.0	Jun-93	266	229.1	276.0	0.0	Jun-93	720	37.0	69.0	0.0
Jul-93	570	121.5	96.7	0.0	Jul-93	246	249.6	333.3	0.0	Jul-93	744	35.7	65.5	0.0
Aug-93	578	118.5	97.8	0.0	Aug-93	291	226.1	336.0	0.0	Aug-93	744	35.1	66.0	0.0
Sep-93	588	110.7	96.8	0.0	Sep-93	213	182.2	268.1	0.0	Sep-93	672	31.7	60.8	0.0
Oct-93	624	110.4	101.5	0.0	Oct-93	309	197.0	297.3	0.0	Oct-93	744	28.9	58.0	0.0
Nov-93	487	107.1	99.7	0.0	Nov-93	261	226.1	365.8	0.0	Nov-93	720	27.2	50.8	0.0
Dec-93	474	135.9	136.3	0.0	Dec-93	744	63.8	97.2	0.0	Dec-93	744	26.7	51.0	0.0
Jan-94	463	140.4	151.0	0.0	Jan-94	193	230.1	372.0	0.0	Jan-94	720	27.5	54.9	0.0
Feb-94	465	127.0	150.5	0.0	Feb-94	191	207.6	317.3	0.0	Feb-94	588	24.2	48.7	0.0
Mar-94	582	112.0	149.8	0.0	Mar-94	216	157.2	243.0	0.0	Mar-94	744	22.8	43.2	0.0
Apr-94	537	119.6	180.3	0.0	Apr-94	192	226.8	357.1	0.0	Apr-94	696	21.1	41.3	0.0
May-94	600	120.0	186.8	0.0	May-94	192	183.3	278.4	0.0	May-94	744	21.2	41.6	0.0
Jun-94	607	108.9	181.4	0.0	Jun-94	231	118.6	145.1	0.0	Jun-94	480	38.6	82.5	0.0
Jul-94	655	100.6	183.4	0.0	Jul-94	264	134.5	161.9	0.0	Jul-94	288	42.7	91.1	0.0
Aug-94	546	95.9	185.0	0.0	Aug-94	480	52.0	63.2	0.0	Aug-94	264	36.0	66.7	0.0
Sep-94	474	94.2	176.5	0.0	Sep-94	112	160.1	195.5	0.0	Sep-94	312	24.6	39.6	0.0

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

Table 4.2: Production Match (Continued)

Date	Well	8-17-37-7W5			Date	Well	14-7-37-7W5			Date	Well	14-12-37-8W5		
	Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d		Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d		Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d
Oct-87					Oct-87					Oct-87				
Nov-87					Nov-87					Nov-87				
Dec-87					Dec-87					Dec-87				
Jan-88					Jan-88					Jan-88				
Feb-88					Feb-88					Feb-88				
Mar-88					Mar-88					Mar-88				
Apr-88					Apr-88					Apr-88				
May-88					May-88					May-88				
Jun-88					Jun-88					Jun-88				
Jul-88					Jul-88					Jul-88				
Aug-88					Aug-88					Aug-88				
Sep-88					Sep-88					Sep-88				
Oct-88					Oct-88					Oct-88				
Nov-88					Nov-88					Nov-88				
Dec-88					Dec-88					Dec-88				
Jan-89					Jan-89					Jan-89				
Feb-89					Feb-89					Feb-89				
Mar-89					Mar-89					Mar-89				
Apr-89					Apr-89					Apr-89				
May-89					May-89					May-89				
Jun-89					Jun-89					Jun-89				
Jul-89					Jul-89					Jul-89				
Aug-89					Aug-89					Aug-89				
Sep-89					Sep-89					Sep-89				
Oct-89					Oct-89					Oct-89				
Nov-89					Nov-89					Nov-89				
Dec-89					Dec-89					Dec-89				
Jan-90					Jan-90					Jan-90				
Feb-90					Feb-90					Feb-90				
Mar-90					Mar-90					Mar-90				
Apr-90					Apr-90					Apr-90				
May-90					May-90					May-90				
Jun-90					Jun-90					Jun-90				
Jul-90					Jul-90					Jul-90				
Aug-90					Aug-90					Aug-90				
Sep-90					Sep-90					Sep-90				
Oct-90					Oct-90					Oct-90				
Nov-90					Nov-90					Nov-90				
Dec-90					Dec-90					Dec-90				
Jan-91					Jan-91					Jan-91				
Feb-91					Feb-91					Feb-91				
Mar-91					Mar-91					Mar-91				
Apr-91					Apr-91					Apr-91				
May-91					May-91					May-91				
Jun-91					Jun-91					Jun-91				
Jul-91					Jul-91					Jul-91				
Aug-91					Aug-91					Aug-91				
Sep-91					Sep-91					Sep-91				
Oct-91					Oct-91					Oct-91				
Nov-91					Nov-91					Nov-91				
Dec-91					Dec-91					Dec-91				
Jan-92					Jan-92					Jan-92				
Feb-92					Feb-92					Feb-92				
Mar-92					Mar-92					Mar-92				
Apr-92					Apr-92					Apr-92				
May-92					May-92					May-92				
Jun-92					Jun-92					Jun-92				
Jul-92					Jul-92					Jul-92				
Aug-92					Aug-92					Aug-92				
Sep-92					Sep-92					Sep-92				
Oct-92					Oct-92					Oct-92				
Nov-92					Nov-92					Nov-92				
Dec-92					Dec-92					Dec-92				
Jan-93					Jan-93					Jan-93				
Feb-93					Feb-93					Feb-93				
Mar-93	12	561.1	474.1	0.0	Mar-93					Mar-93				
Apr-93	472	499.1	397.5	0.0	Apr-93					Apr-93				
May-93					May-93					May-93				
Jun-93	238	524.7	418.9	0.0	Jun-93	72	191.2	173.1	0.0	Jun-93				
Jul-93	118	538.3	442.9	0.0	Jul-93	465	389.0	556.7	0.0	Jul-93				
Aug-93	119	527.0	434.1	0.0	Aug-93	474	380.5	746.6	0.0	Aug-93				
Sep-93	116	526.1	433.1	0.0	Sep-93					Sep-93	333	303.5	237.7	0.0
Oct-93	120	526.0	437.4	0.0	Oct-93					Oct-93	744	132.6	103.5	0.0
Nov-93	126	488.7	499.1	0.0	Nov-93	189	355.4	478.6	0.0	Nov-93	597	146.9	113.4	0.0
Dec-93	271	235.1	588.8	0.0	Dec-93	227	281.5	481.7	0.0	Dec-93	528	130.5	100.5	0.0
Jan-94	290	222.7	484.7	0.0	Jan-94	307	216.2	430.9	0.0	Jan-94	528	134.8	103.5	0.0
Feb-94	324	184.9	384.0	0.0	Feb-94	293	196.6	440.1	0.0	Feb-94	437	132.0	101.1	0.0
Mar-94	401	161.6	325.9	0.0	Mar-94	206	190.0	438.5	0.0	Mar-94	541	126.2	96.2	0.0
Apr-94	377	148.1	303.5	0.0	Apr-94	234	180.1	431.7	0.0	Apr-94	499	122.9	93.3	0.0
May-94	286	151.3	293.7	0.0	May-94	198	174.4	404.8	0.0	May-94	575	117.9	89.1	0.0
Jun-94	236	149.4	268.7	0.0	Jun-94	222	161.1	337.7	0.0	Jun-94	577	114.6	86.2	0.0
Jul-94	211	148.8	277.5	0.0	Jul-94	217	160.2	333.9	0.0	Jul-94	587	111.7	83.8	0.0
Aug-94	192	155.6	321.1	0.0	Aug-94	193	154.7	331.1	0.0	Aug-94	610	108.3	77.7	0.0
Sep-94	167	161.0	340.5	0.0	Sep-94	169	143.7	300.3	0.0	Sep-94	413	83.4	62.3	0.0

MRL = 88 STB/d	MRL = 88 STB/d	MRL = 88 STB/d
GOR = 1.129 Mscf/STB	GOR = 1.129 Mscf/STB	GOR = 1.129 Mscf/STB

Table 4.2: Production Match (Continued)

Date	Well	16-12-37-8W5			Date	Well	8-7-37-7W5			Cumulative Pool Production				
	Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d	Date	Prod hrs	Oil STB/d	Gas Mscf/d	Water STB/d	Date	Oil MSTB	Gas MMscf	Water MSTB	Wells Producing
Oct-87					Oct-87					Oct-87				
Nov-87					Nov-87					Nov-87	0.8	1.0	0.0	1
Dec-87					Dec-87					Dec-87	1.2	2.0	0.0	1
Jan-88					Jan-88					Jan-88	1.7	3.0	0.0	1
Feb-88					Feb-88					Feb-88	2.4	4.5	0.0	1
Mar-88					Mar-88					Mar-88	3.0	5.9	0.0	1
Apr-88					Apr-88					Apr-88	3.5	7.0	0.0	1
May-88					May-88					May-88	4.1	8.2	0.0	1
Jun-88					Jun-88					Jun-88	4.6	9.0	0.0	1
Jul-88					Jul-88					Jul-88	5.2	9.9	0.0	1
Aug-88					Aug-88					Aug-88	5.7	10.8	0.0	1
Sep-88					Sep-88					Sep-88	6.2	11.6	0.0	1
Oct-88					Oct-88					Oct-88	6.8	12.5	0.0	1
Nov-88					Nov-88					Nov-88	7.3	13.3	0.0	1
Dec-88					Dec-88					Dec-88	7.8	14.1	0.0	1
Jan-89					Jan-89					Jan-89	8.4	15.0	0.0	1
Feb-89					Feb-89					Feb-89	8.9	15.7	0.0	1
Mar-89					Mar-89					Mar-89	12.0	19.2	0.0	2
Apr-89					Apr-89					Apr-89	14.6	22.1	0.0	2
May-89					May-89					May-89	16.8	24.6	0.0	2
Jun-89					Jun-89					Jun-89	18.8	27.0	0.0	2
Jul-89					Jul-89					Jul-89	19.7	28.2	0.0	2
Aug-89					Aug-89					Aug-89	20.6	29.4	0.0	2
Sep-89					Sep-89					Sep-89	21.7	30.7	0.0	2
Oct-89					Oct-89					Oct-89	22.5	31.7	0.0	2
Nov-89					Nov-89					Nov-89	23.3	32.7	0.0	2
Dec-89					Dec-89					Dec-89	24.1	33.8	0.0	2
Jan-90					Jan-90					Jan-90	25.1	34.9	0.0	2
Feb-90					Feb-90					Feb-90	26.0	36.0	0.0	2
Mar-90					Mar-90					Mar-90	29.2	39.2	0.0	3
Apr-90					Apr-90					Apr-90	30.8	40.9	0.0	3
May-90					May-90					May-90	40.2	49.5	0.0	3
Jun-90					Jun-90					Jun-90	47.3	56.1	0.0	3
Jul-90					Jul-90					Jul-90	49.0	57.8	0.0	3
Aug-90					Aug-90					Aug-90	56.6	64.9	0.0	4
Sep-90					Sep-90					Sep-90	63.9	71.8	0.0	4
Oct-90					Oct-90					Oct-90	76.0	82.9	0.0	5
Nov-90					Nov-90					Nov-90	88.2	94.2	0.0	5
Dec-90					Dec-90					Dec-90	102.5	107.3	0.0	5
Jan-91					Jan-91					Jan-91	108.9	113.6	0.0	4
Feb-91					Feb-91					Feb-91	122.1	125.6	0.0	6
Mar-91					Mar-91					Mar-91	136.3	138.6	0.0	6
Apr-91					Apr-91					Apr-91	150.5	151.6	0.0	6
May-91					May-91					May-91	159.7	160.5	0.0	5
Jun-91					Jun-91					Jun-91	172.0	172.1	0.0	6
Jul-91					Jul-91					Jul-91	184.4	183.6	0.0	6
Aug-91					Aug-91					Aug-91	196.2	194.7	0.0	6
Sep-91					Sep-91					Sep-91	208.4	206.0	0.0	6
Oct-91					Oct-91					Oct-91	220.5	217.1	0.0	6
Nov-91					Nov-91					Nov-91	232.6	228.8	0.0	6
Dec-91					Dec-91					Dec-91	244.6	240.2	0.0	6
Jan-92					Jan-92					Jan-92	257.0	251.7	0.0	6
Feb-92					Feb-92					Feb-92	268.1	262.5	0.0	6
Mar-92					Mar-92					Mar-92	281.1	275.3	0.0	7
Apr-92					Apr-92					Apr-92	293.3	287.4	0.0	6
May-92					May-92					May-92	305.4	300.1	0.0	6
Jun-92					Jun-92					Jun-92	316.9	312.0	0.0	6
Jul-92					Jul-92					Jul-92	331.9	326.7	0.0	7
Aug-92					Aug-92					Aug-92	346.7	341.9	0.0	7
Sep-92					Sep-92					Sep-92	361.8	360.6	0.0	7
Oct-92					Oct-92					Oct-92	379.6	384.1	0.0	8
Nov-92					Nov-92					Nov-92	396.0	405.7	0.0	8
Dec-92					Dec-92					Dec-92	412.5	426.6	0.0	8
Jan-93					Jan-93					Jan-93	428.5	445.1	0.0	8
Feb-93					Feb-93					Feb-93	444.8	465.1	0.0	9
Mar-93					Mar-93					Mar-93	462.7	485.7	0.0	9
Apr-93					Apr-93					Apr-93	489.8	513.9	0.0	9
May-93					May-93					May-93	508.2	536.3	0.0	8
Jun-93					Jun-93					Jun-93	531.2	561.8	0.0	10
Jul-93					Jul-93					Jul-93	558.0	594.8	0.0	10
Aug-93					Aug-93					Aug-93	584.6	632.3	0.0	10
Sep-93					Sep-93					Sep-93	605.7	655.7	0.0	10
Oct-93	185	593.1	494.8	0.0	Oct-93					Oct-93	632.1	684.0	0.0	11
Nov-93	624	421.0	495.5	0.0	Nov-93					Nov-93	666.6	725.1	0.0	12
Dec-93					Dec-93					Dec-93	689.1	757.8	0.0	11
Jan-94					Jan-94					Jan-94	712.0	791.8	0.0	11
Feb-94	215	401.6	382.9	0.0	Feb-94					Feb-94	735.2	825.9	0.0	12
Mar-94	168	379.3	432.1	0.0	Mar-94					Mar-94	758.0	860.4	0.0	12
Apr-94	120	397.4	501.6	0.0	Apr-94	24	562.9	479.1	0.0	Apr-94	779.8	894.6	0.0	13
May-94	144	407.8	532.7	0.0	May-94	158	370.5	306.4	0.0	May-94	803.4	929.4	0.0	13
Jun-94	120	396.5	410.8	0.0	Jun-94	560	305.6	212.5	0.0	Jun-94	830.1	962.5	0.0	13
Jul-94	120	451.6	402.2	0.0	Jul-94	576	239.3	167.3	0.0	Jul-94	854.9	994.2	0.0	13
Aug-94	168	382.9	484.5	0.0	Aug-94	240	271.2	202.1	0.0	Aug-94	875.3	1023.6	0.0	13
Sep-94	168	379.8	520.9	0.0	Sep-94	264	242.3	165.7	0.0	Sep-94	893.6	1050.7	0.0	12

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

Table 4.2: Production Match (Continued)

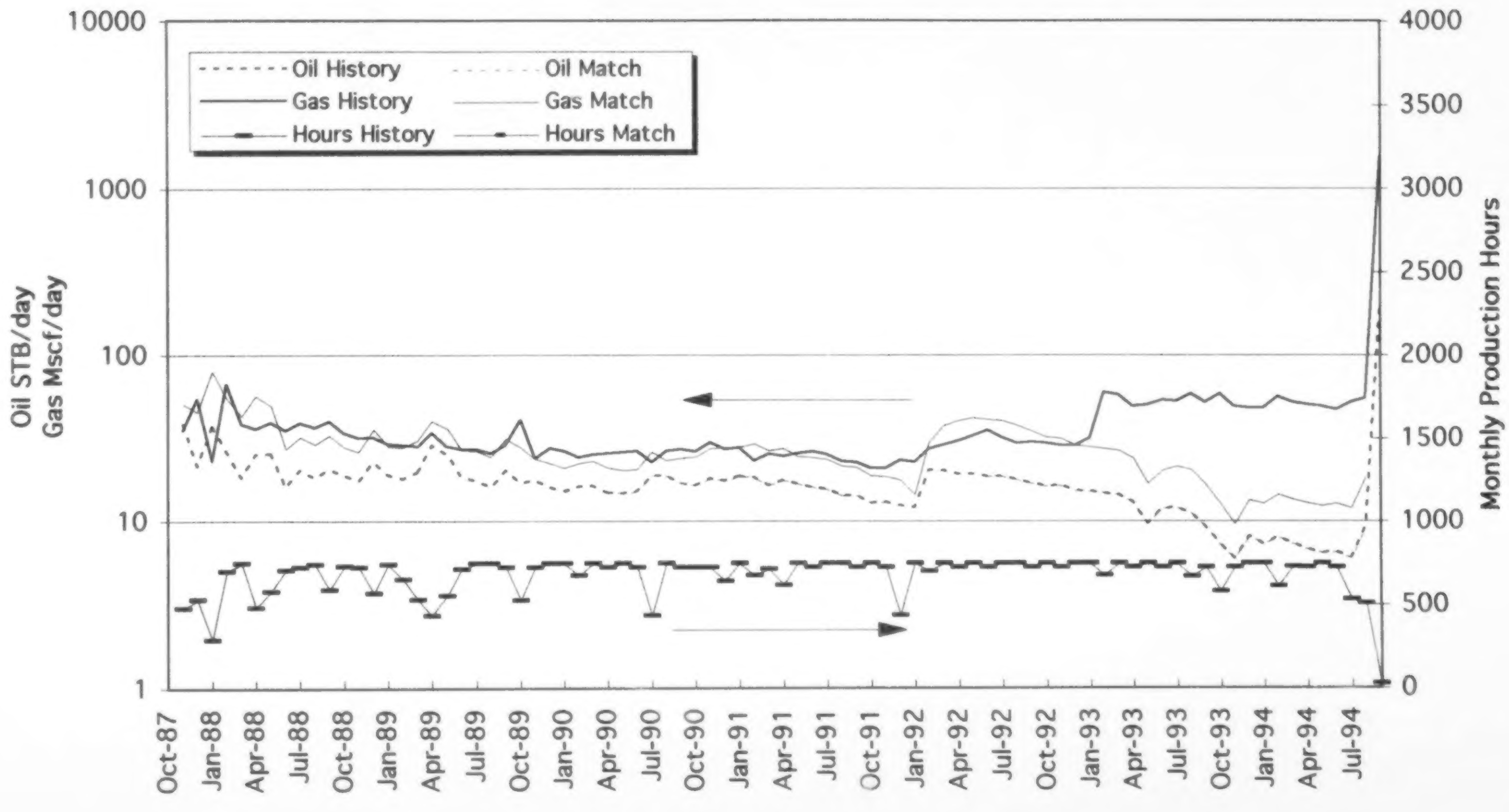

Figure 4.1(a): Oil and Gas Production History Match (16-09-37-7W5)

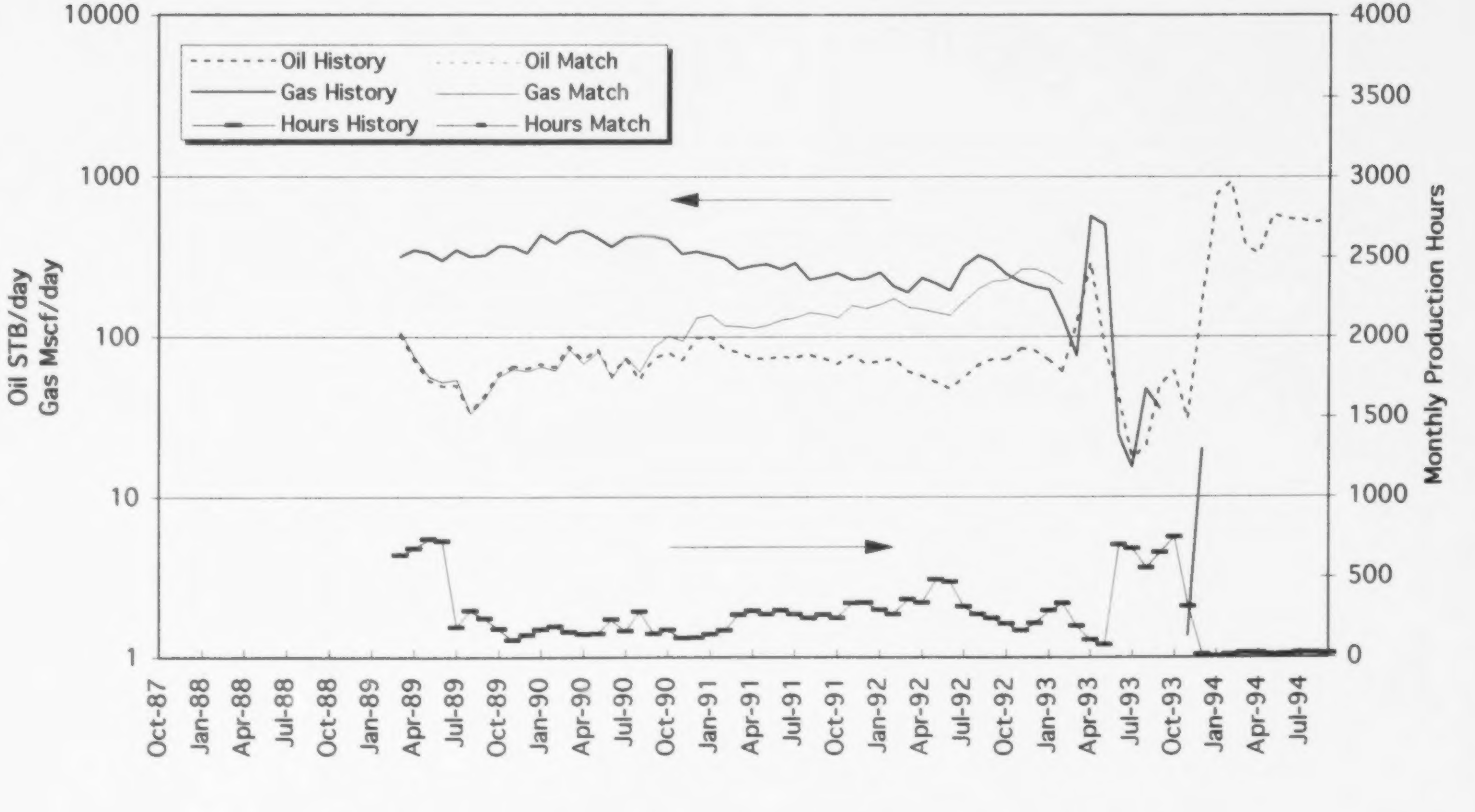

Figure 4.1(b): Oil and Gas Production History Match (06-15-37-7W5)

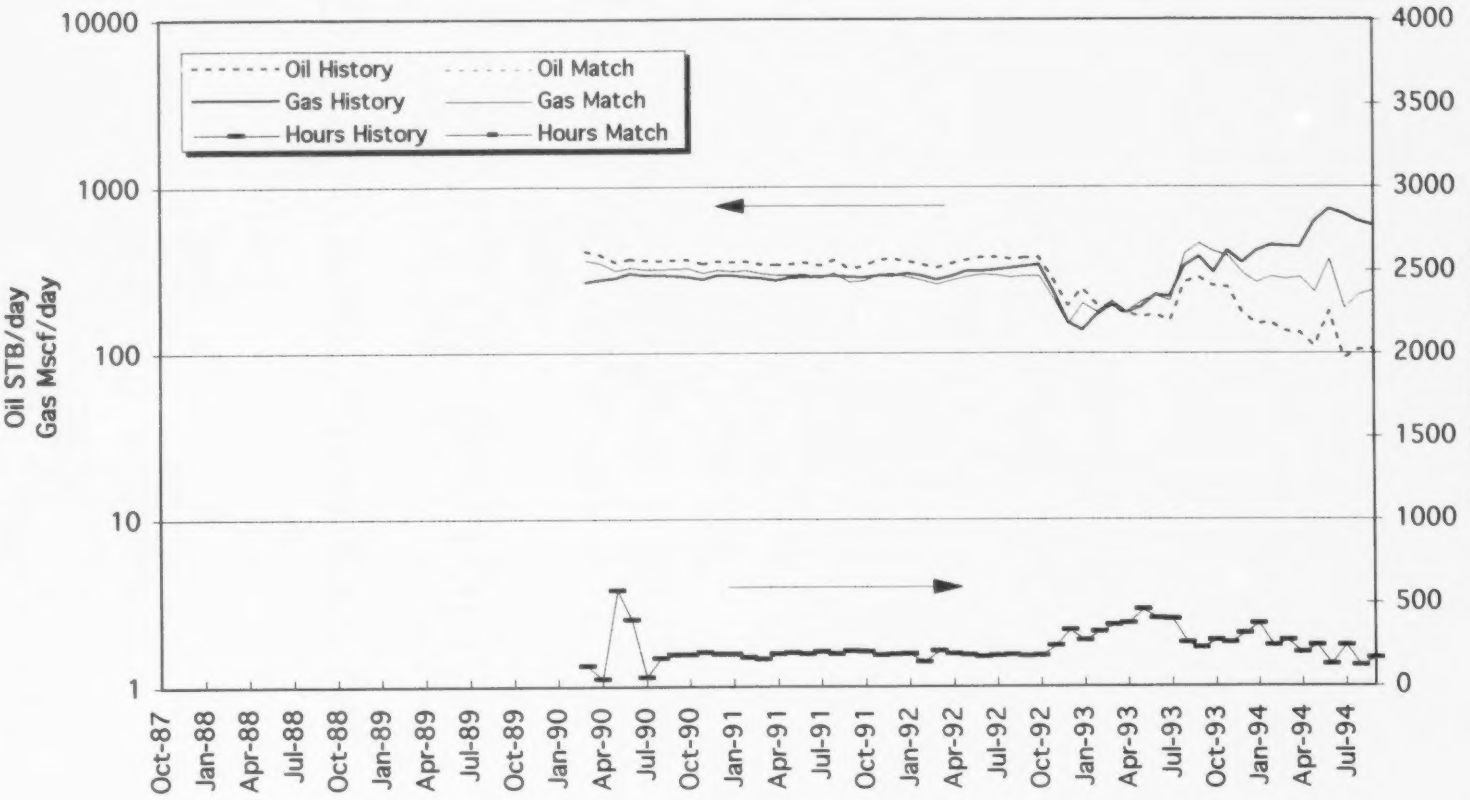

Figure 4.1(c): Oil and Gas Production History Match (08-13-37-8W5)

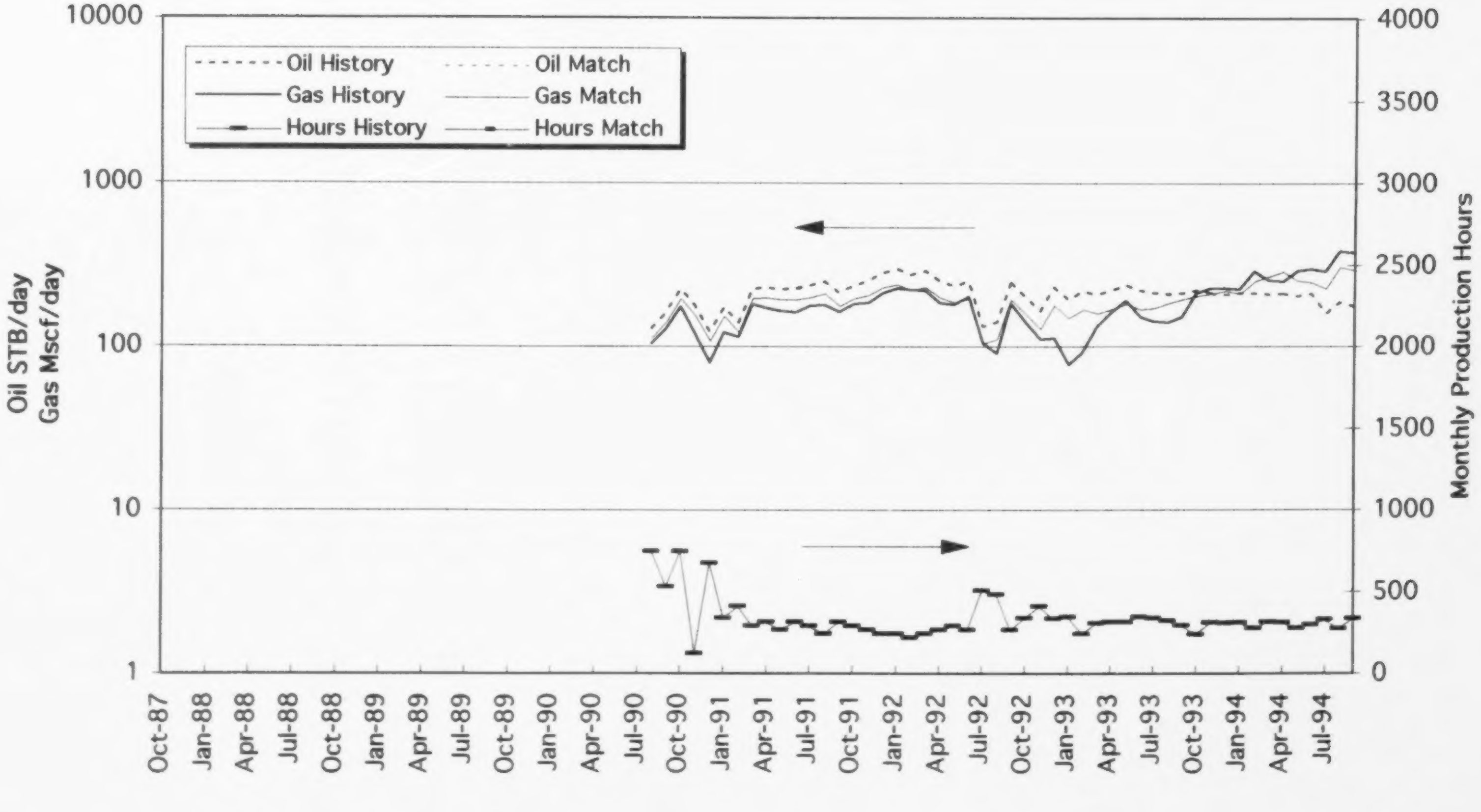

Figure 4.1(d): Oil and Gas Production History Match (06-13-37-8W5)

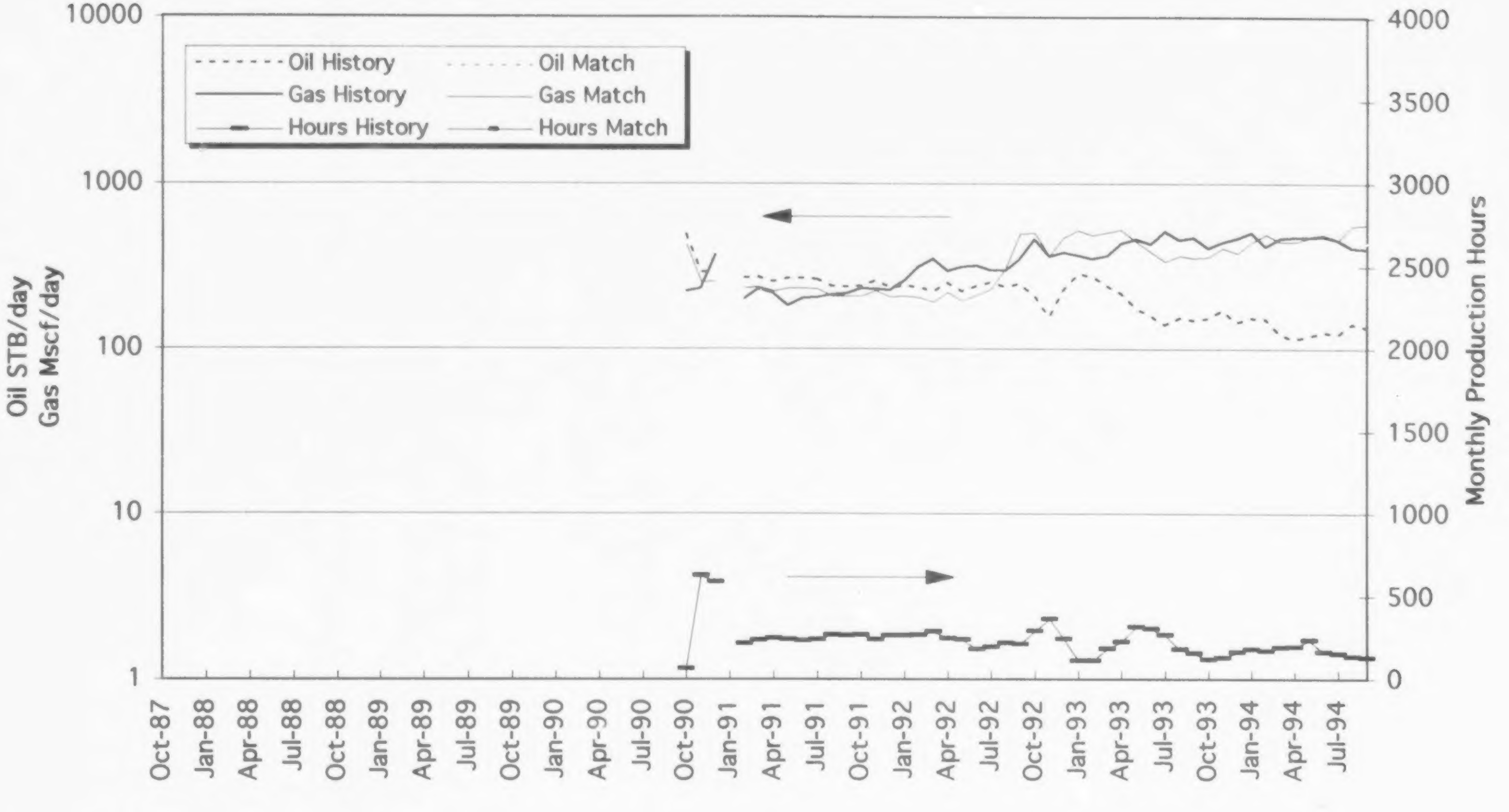

Figure 4.1(e): Oil and Gas Production History Match (06-16-37-7W5)

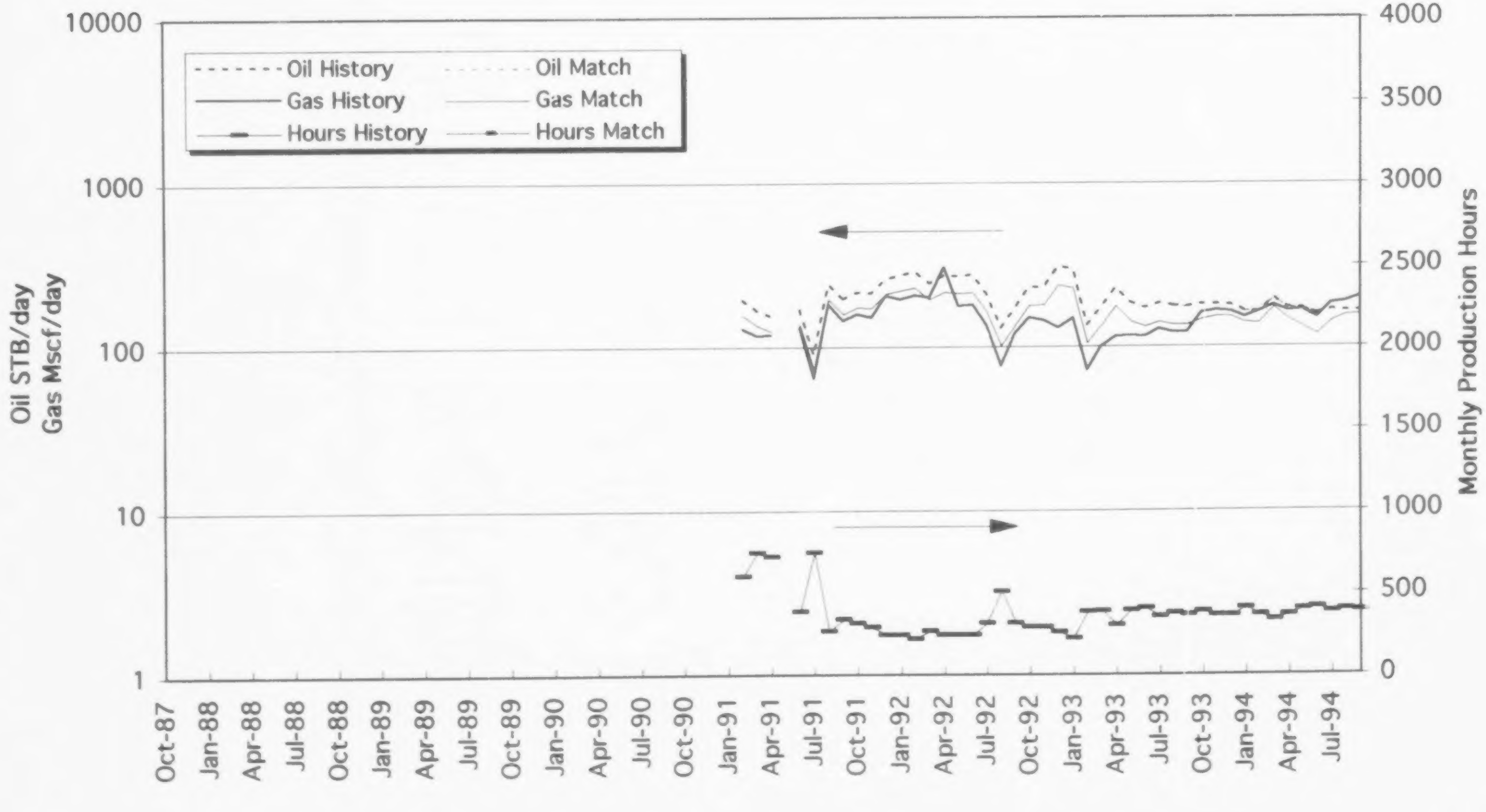

Figure 4.1(f): Oil and Gas Production History Match (08-14-37-8W5)

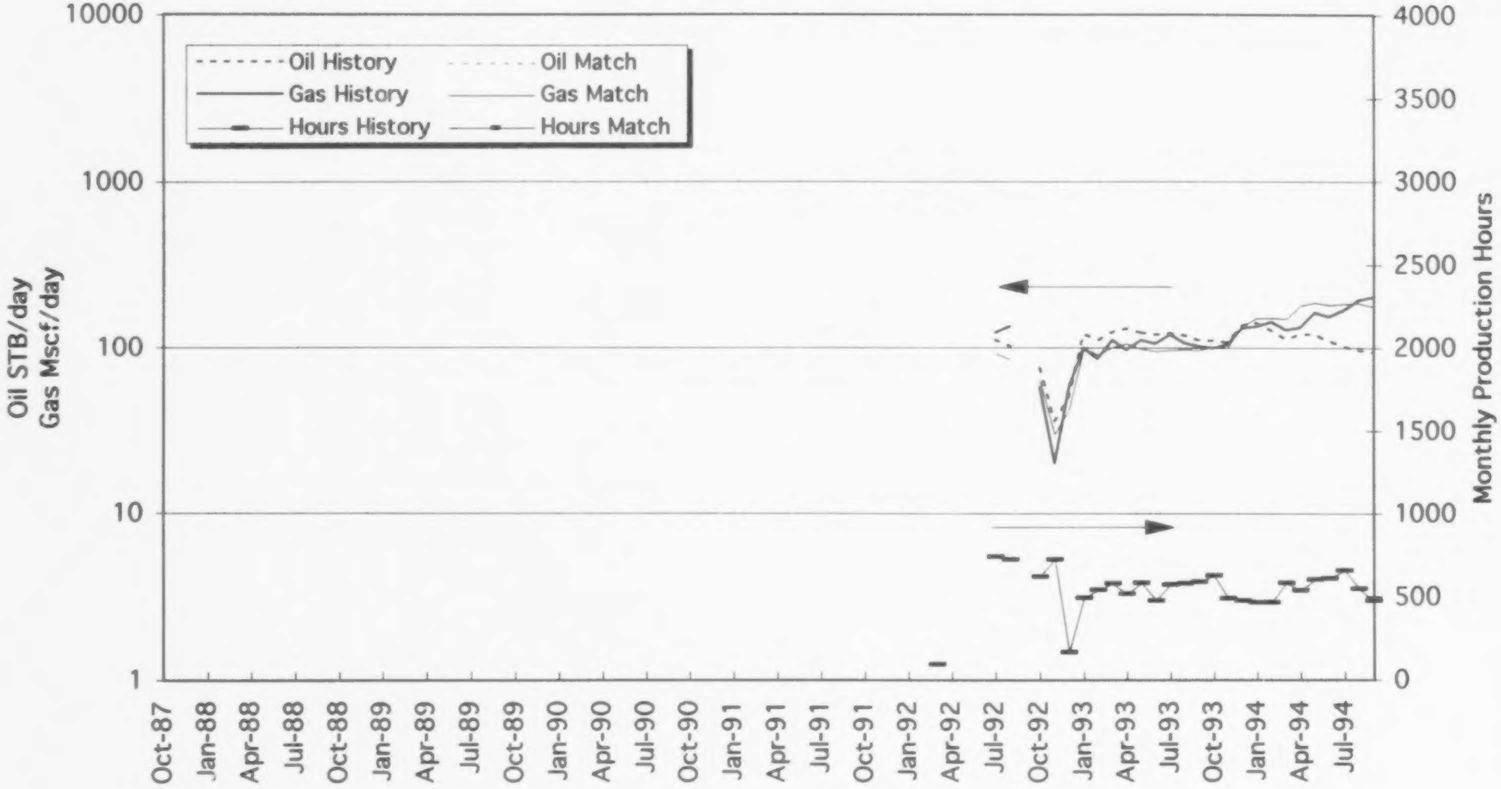

Figure 4.1(g): Oil and Gas Production History Match (08-18-37-7W5)

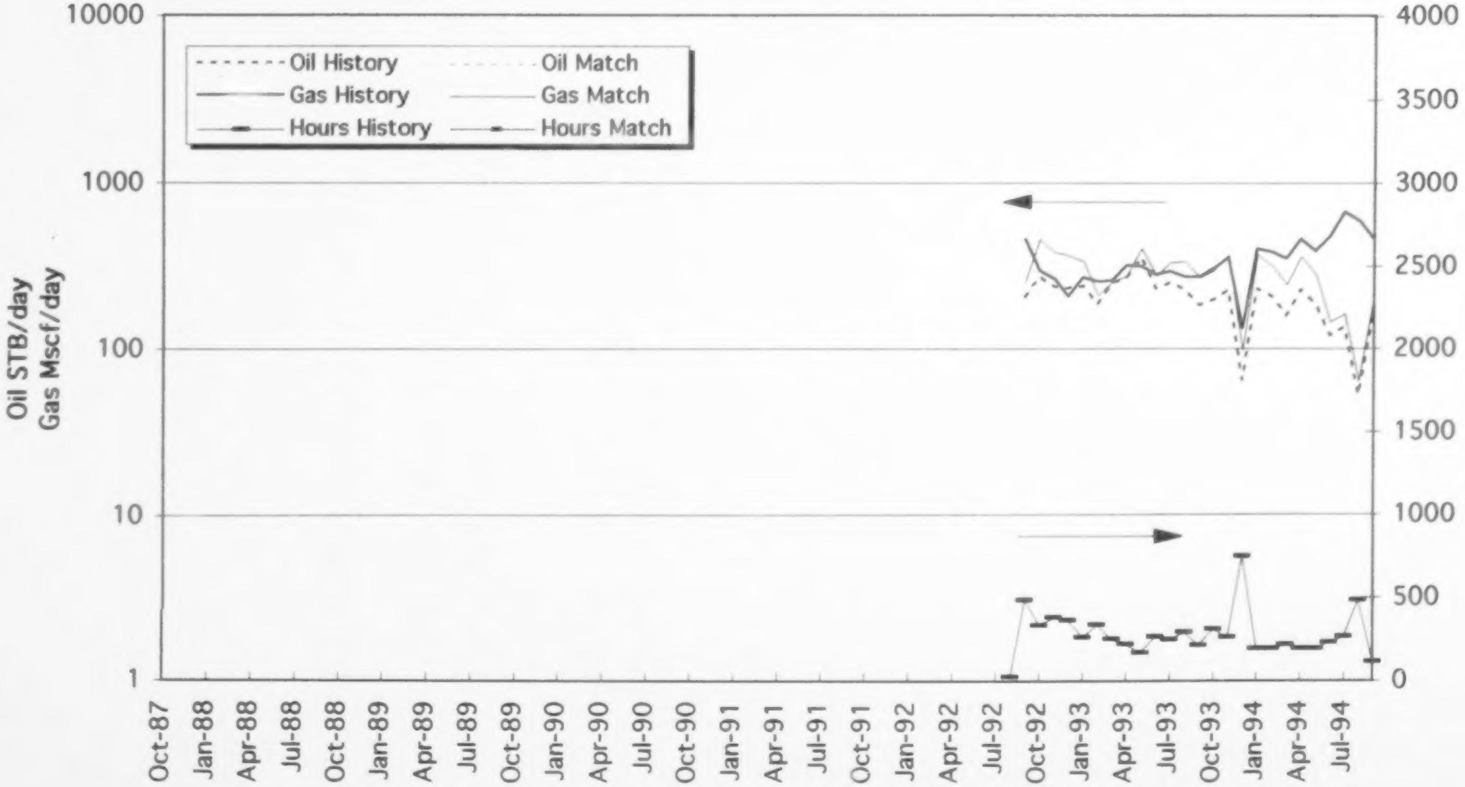

Figure 4.1(h): Oil and Gas Production History Match (16-08-37-7W5)

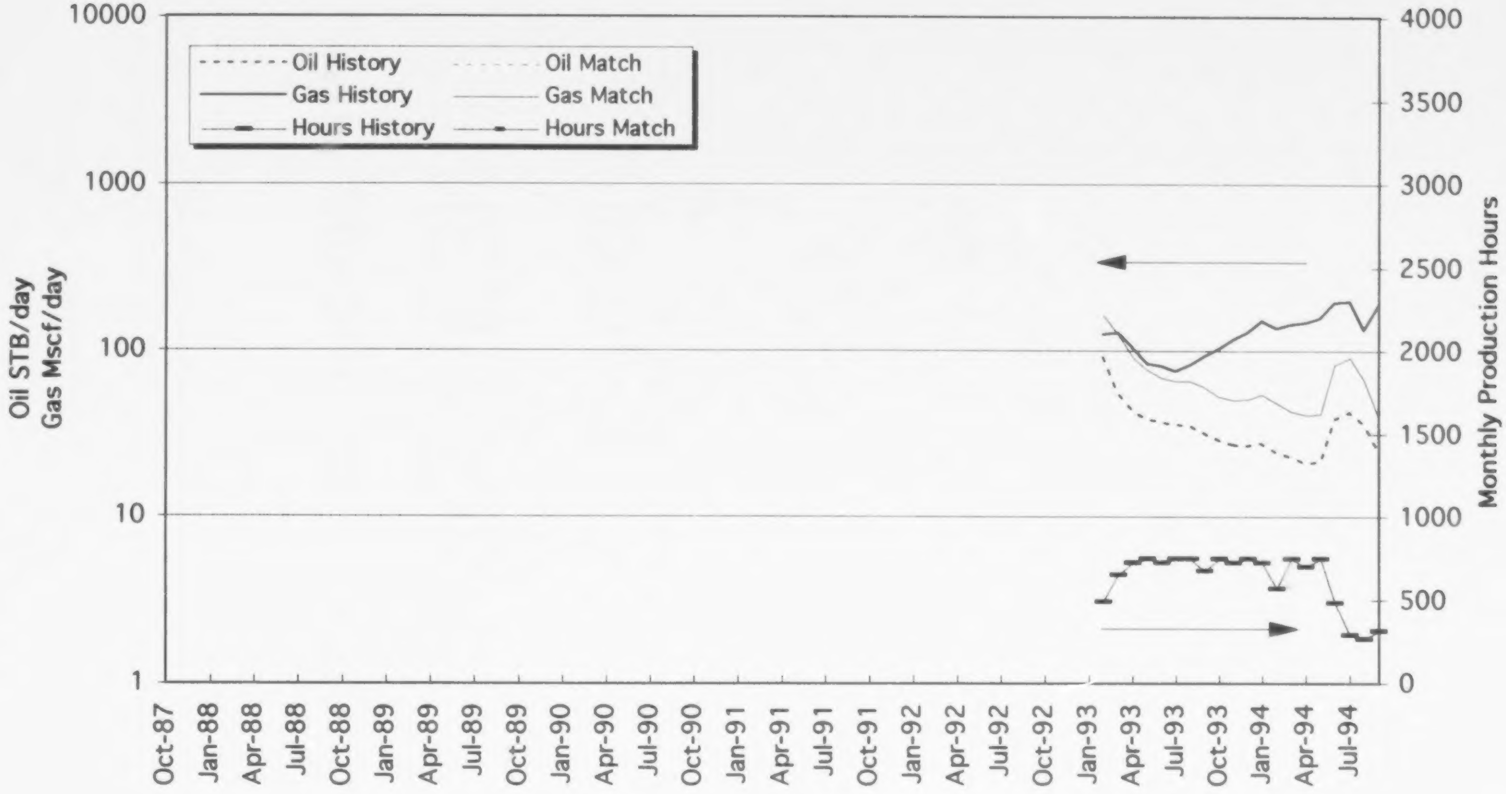

Figure 4.1(i): Oil and Gas Production History Match (14-09-37-7W5)

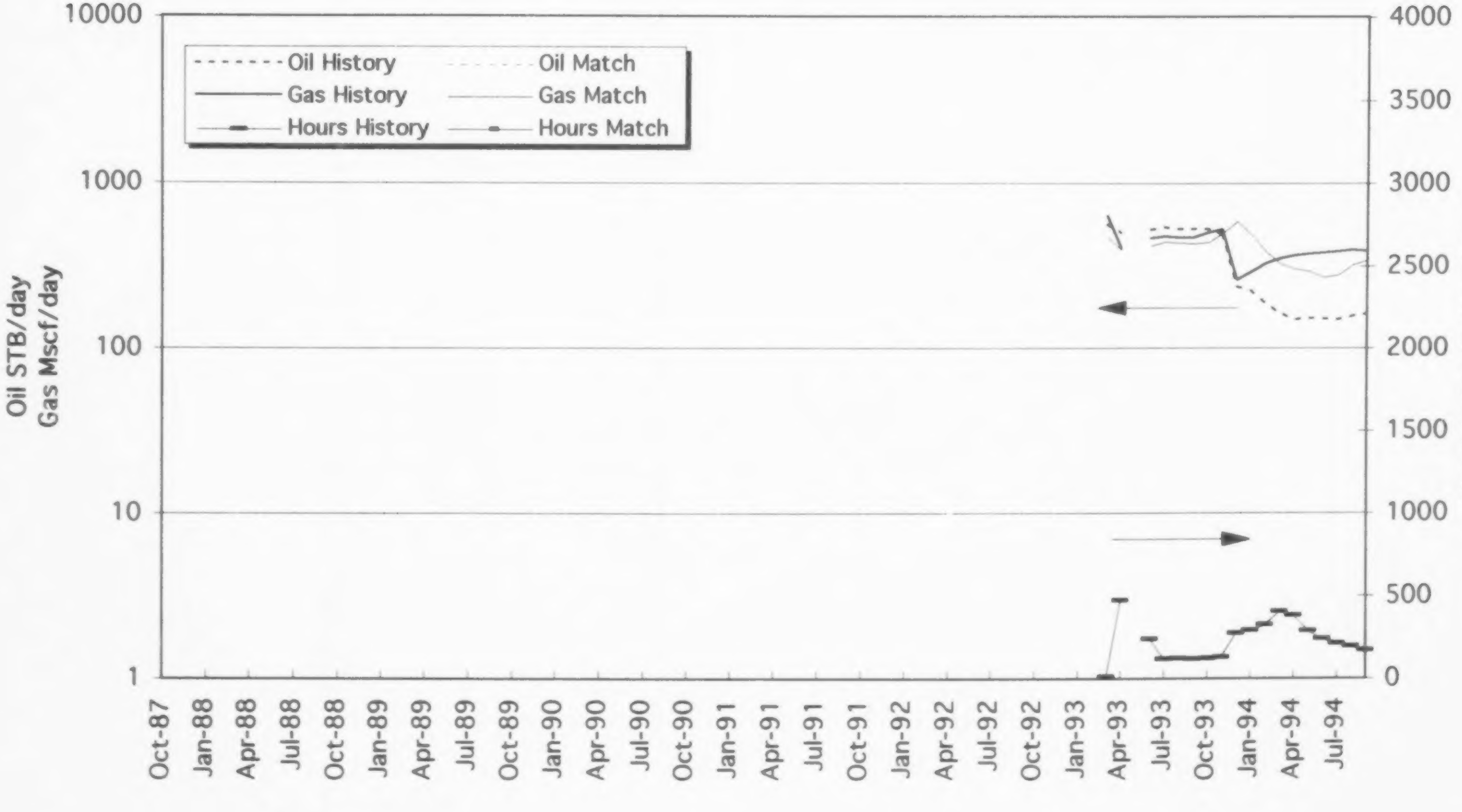

Figure 4.1(j): Oil and Gas Production History Match (08-17-37-7W5)

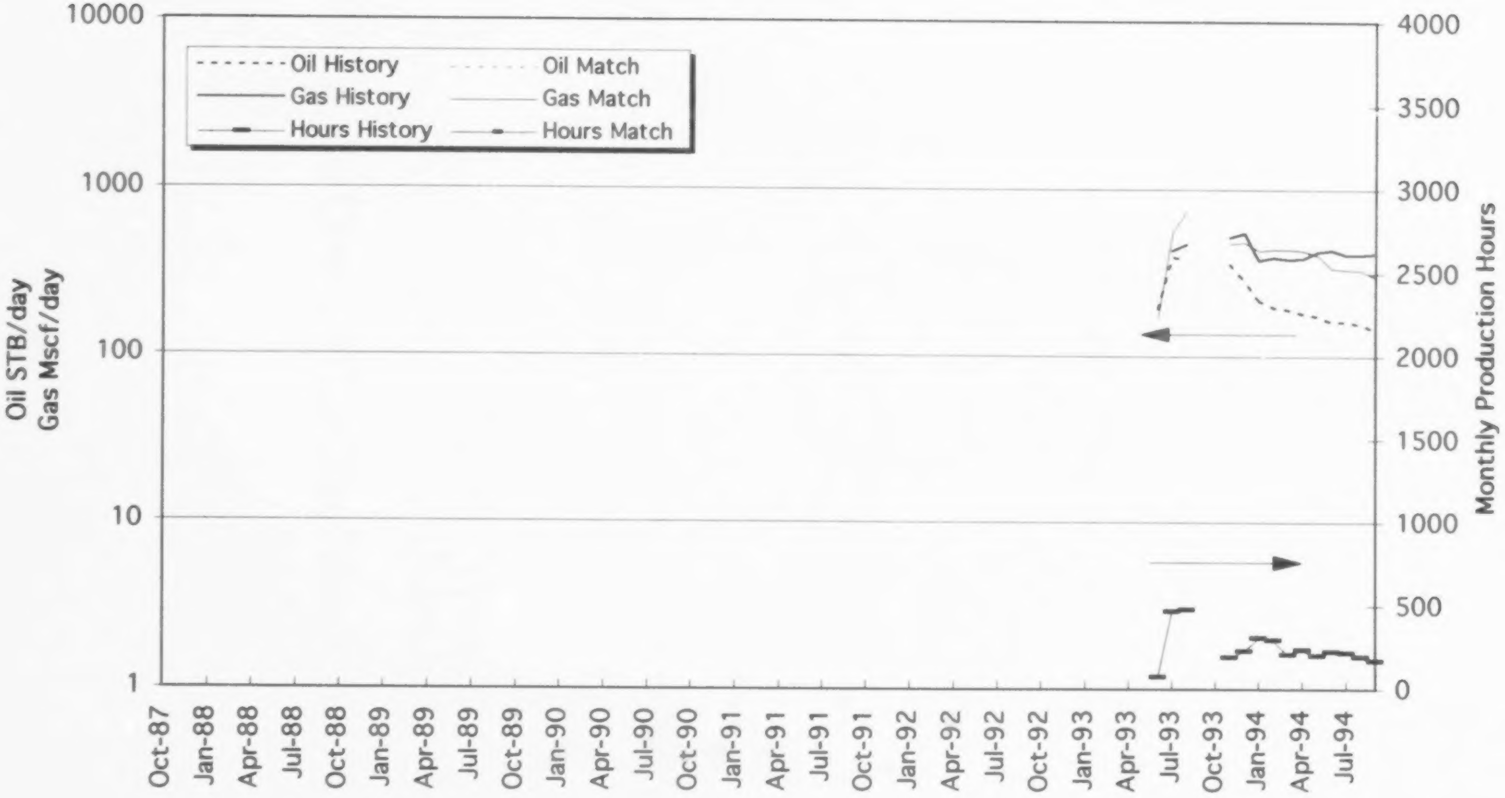

Figure 4.1(k): Oil and Gas Production History Match (14-07-37-7W5)

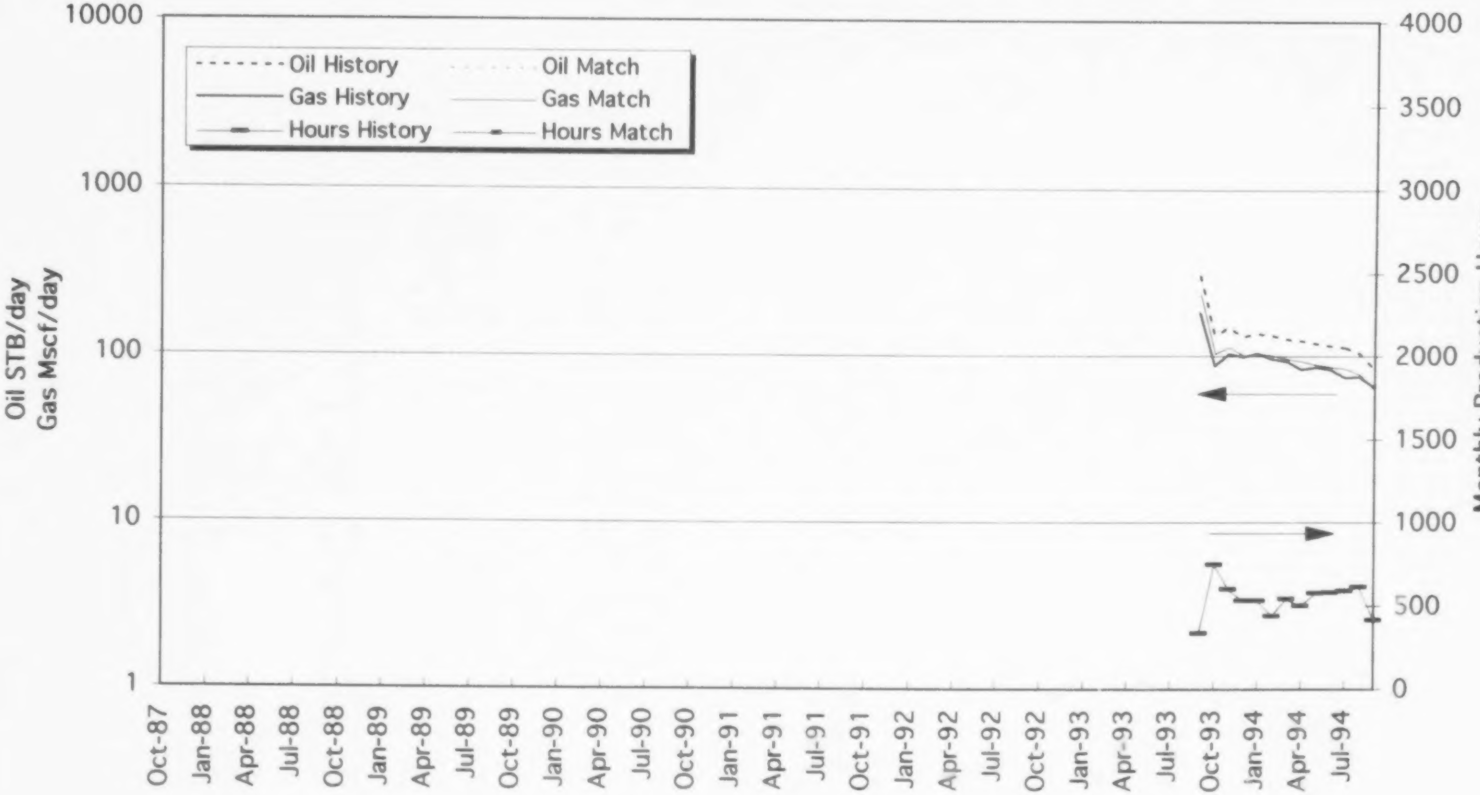

Figure 4.1(I): Oil and Gas Production History Match (14-12-37-8W5)

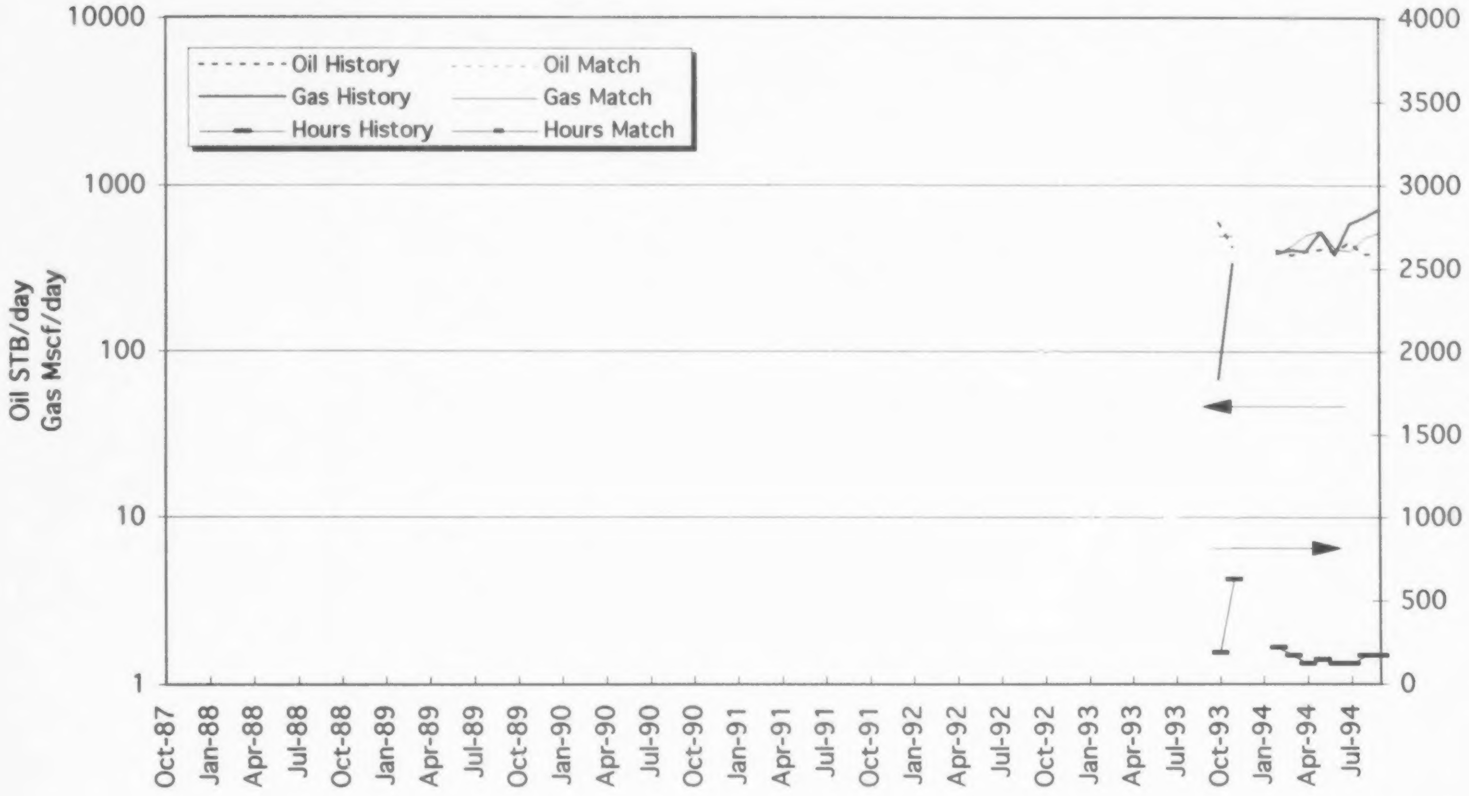

Figure 4.1(m): Oil and Gas Production History Match (16-12-37-8W5)

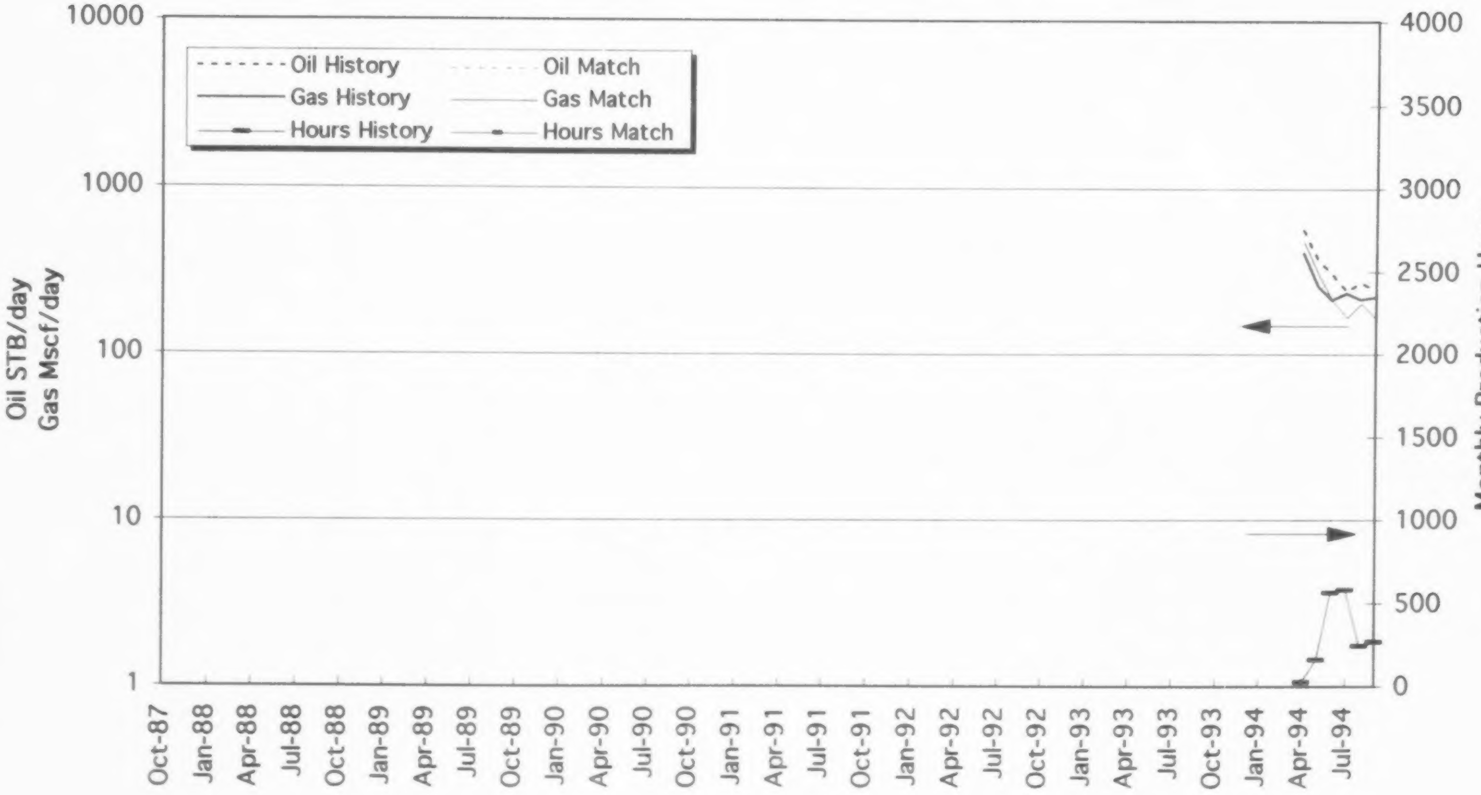

Figure 4.1(n): Oil and Gas Production History Match (08-07-37-7W5)

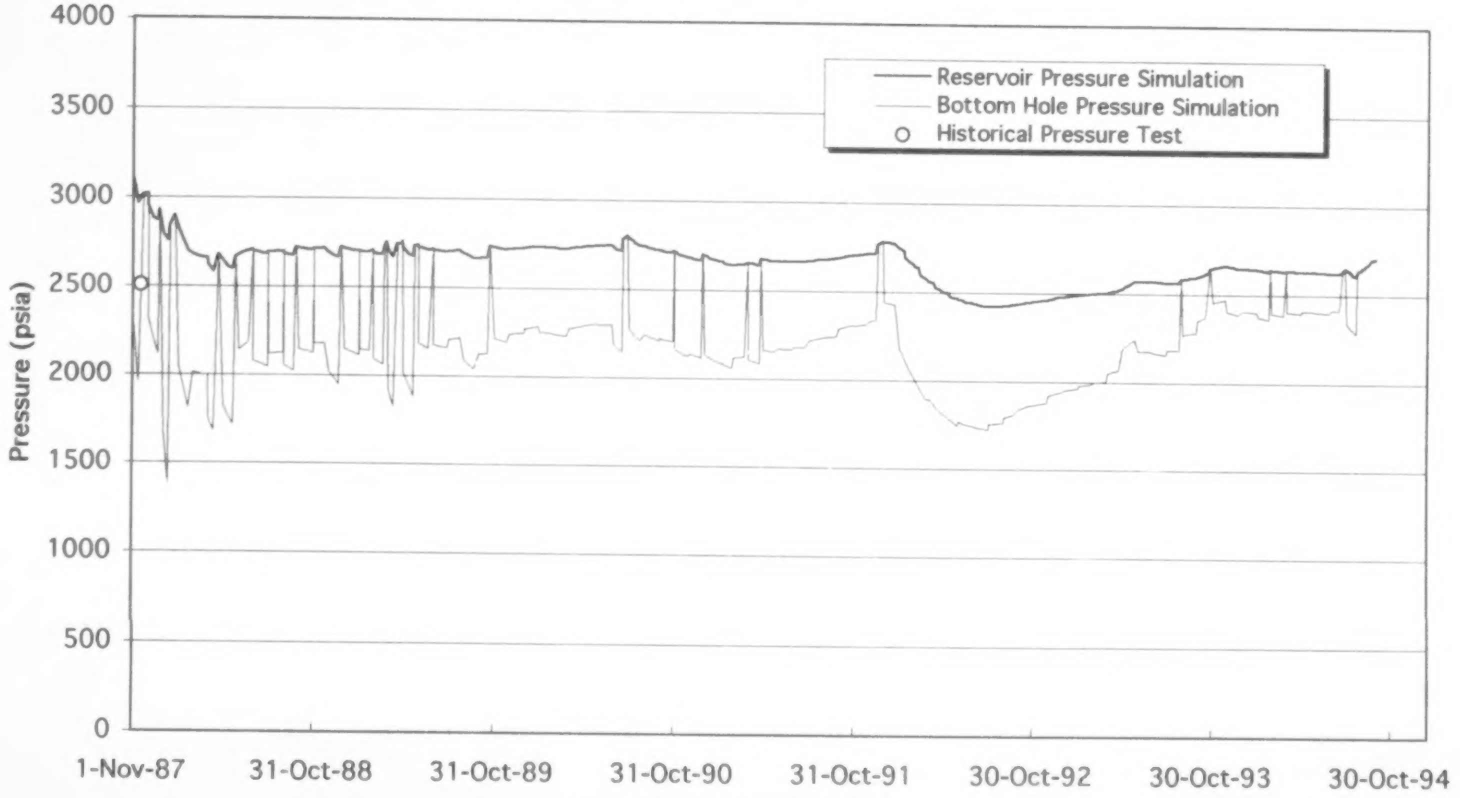

Figure 4.2(a): Pressure History Match (16-09-37-7W5)

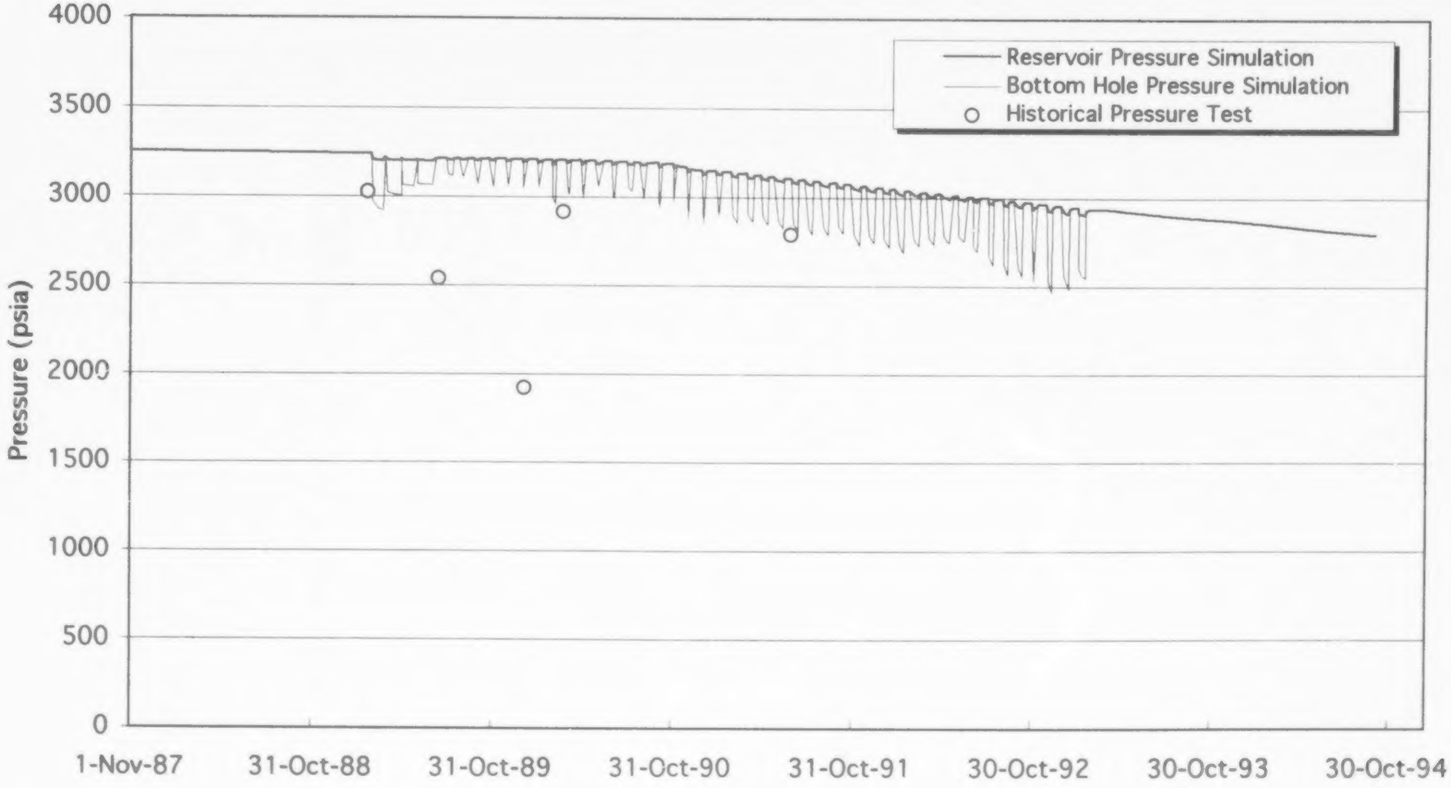

Figure 4.2(b): Pressure History Match (06-15-37-7W5)

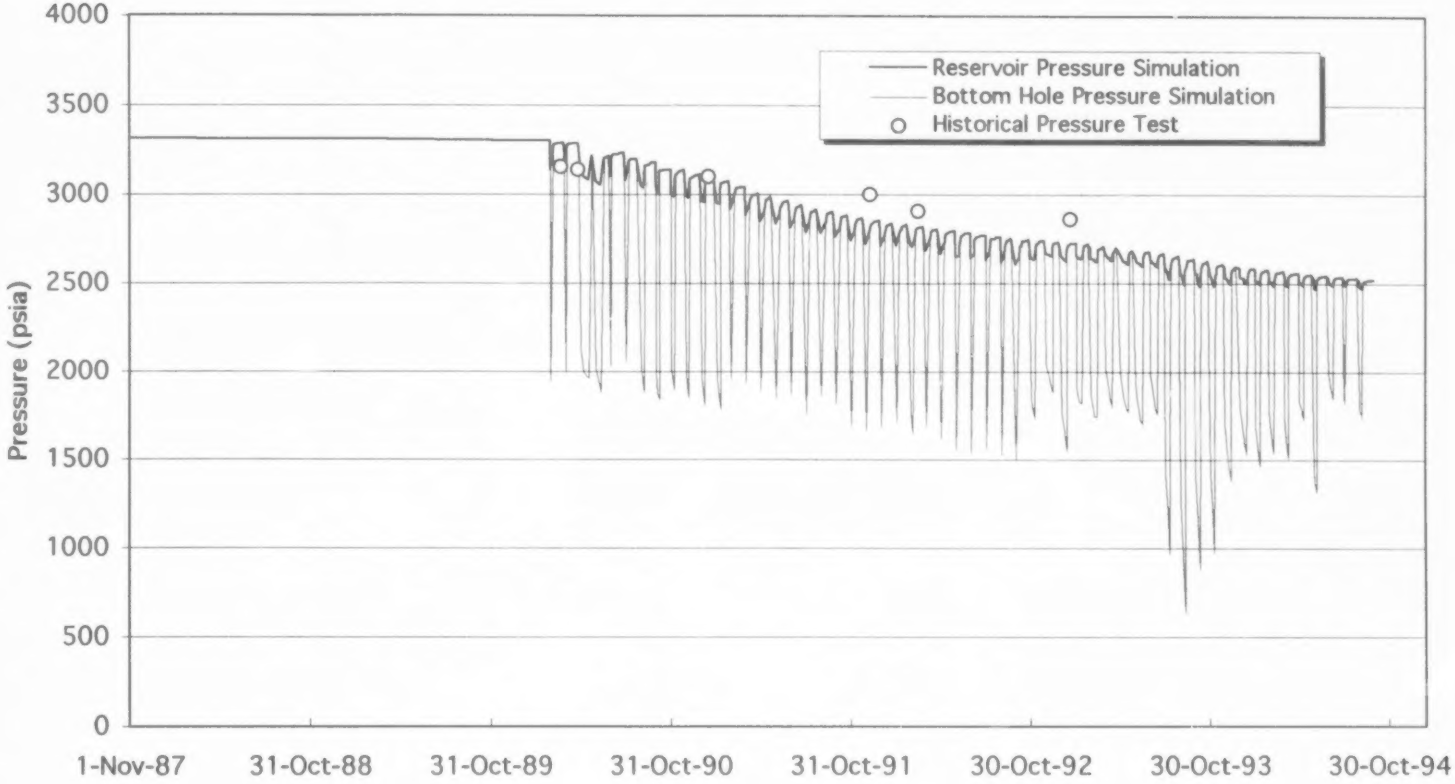

Figure 4.2(c): Pressure History Match (08-13-37-8W5)

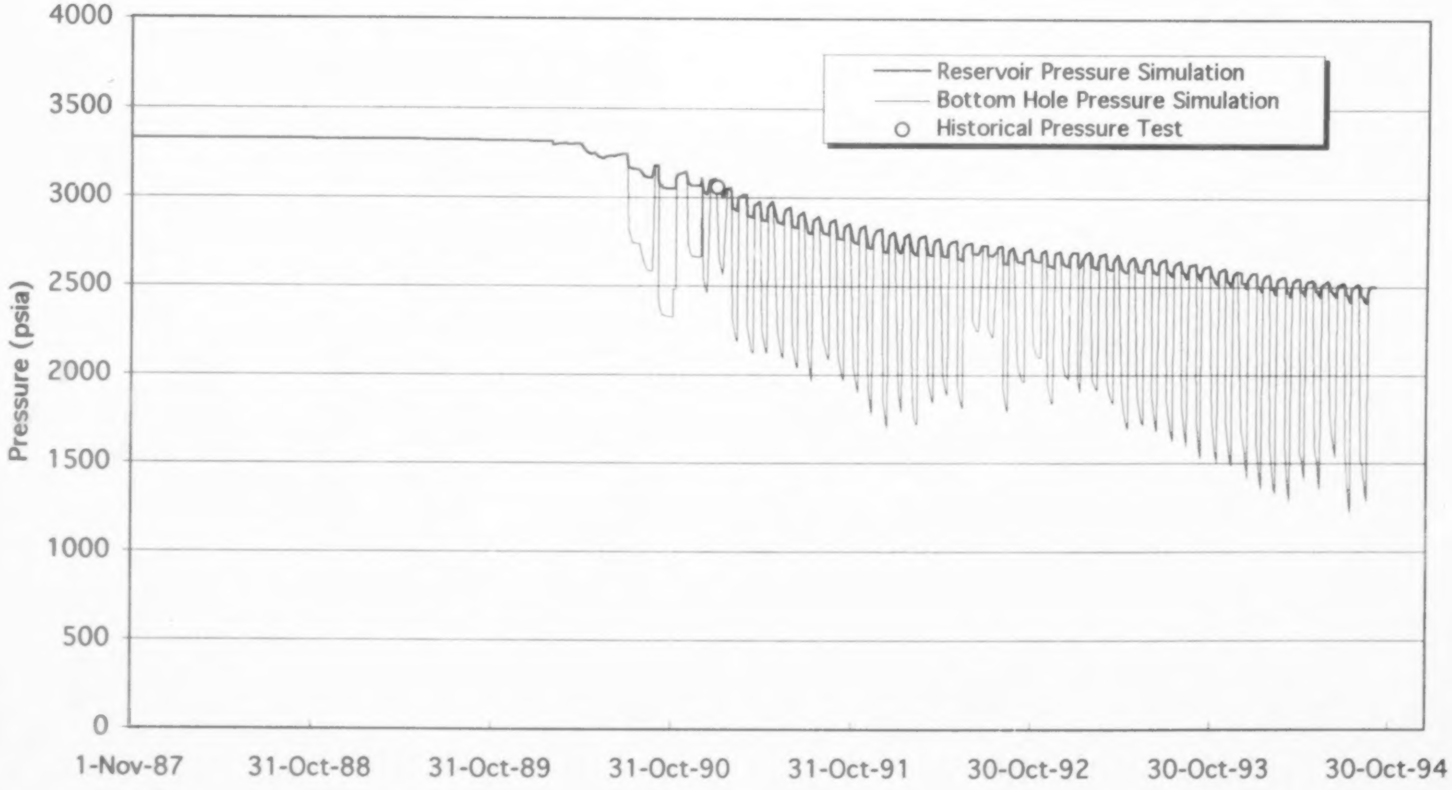

Figure 4.2(d): Pressure History Match (06-13-37-8W5)

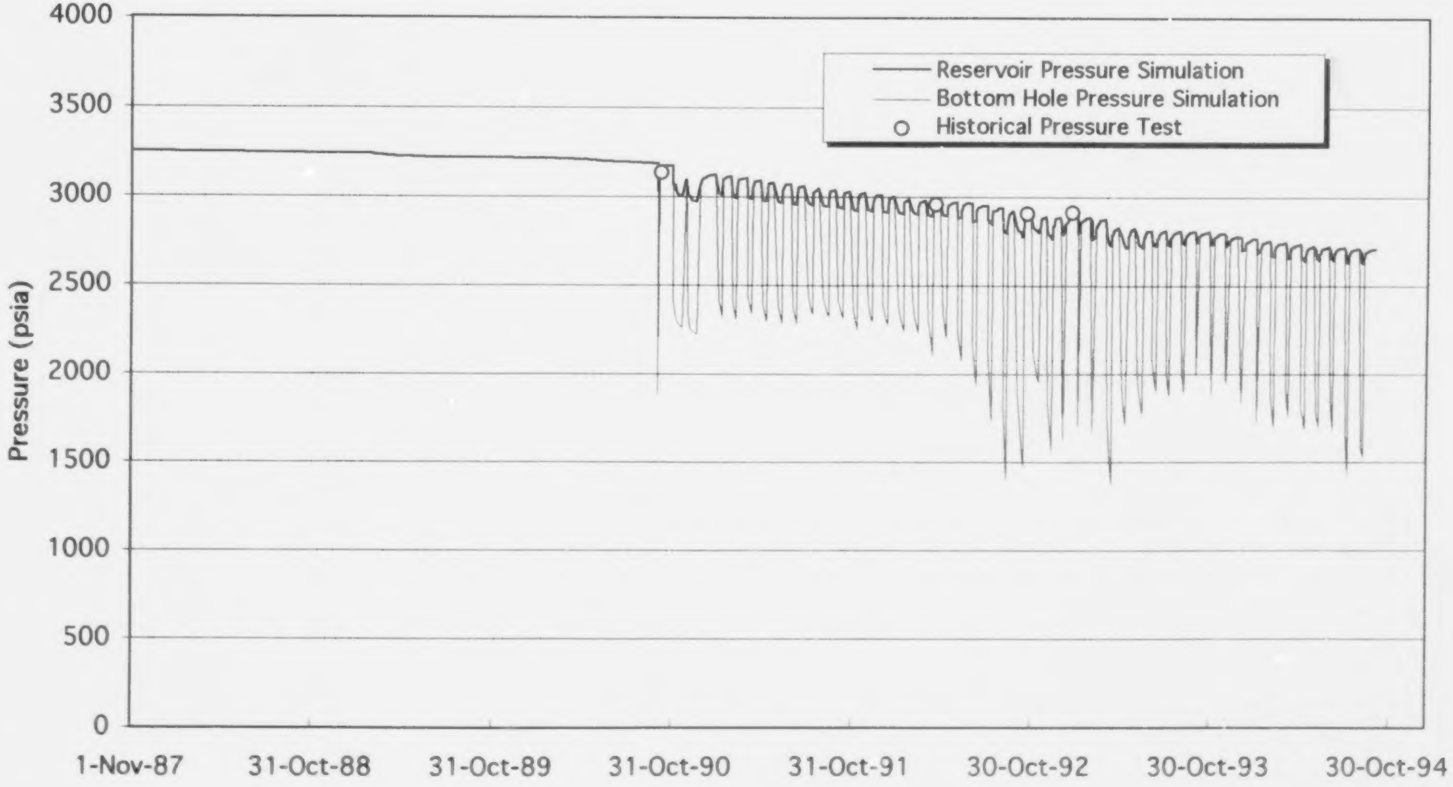

Figure 4.2(e): Pressure History Match (06-16-37-7W5)

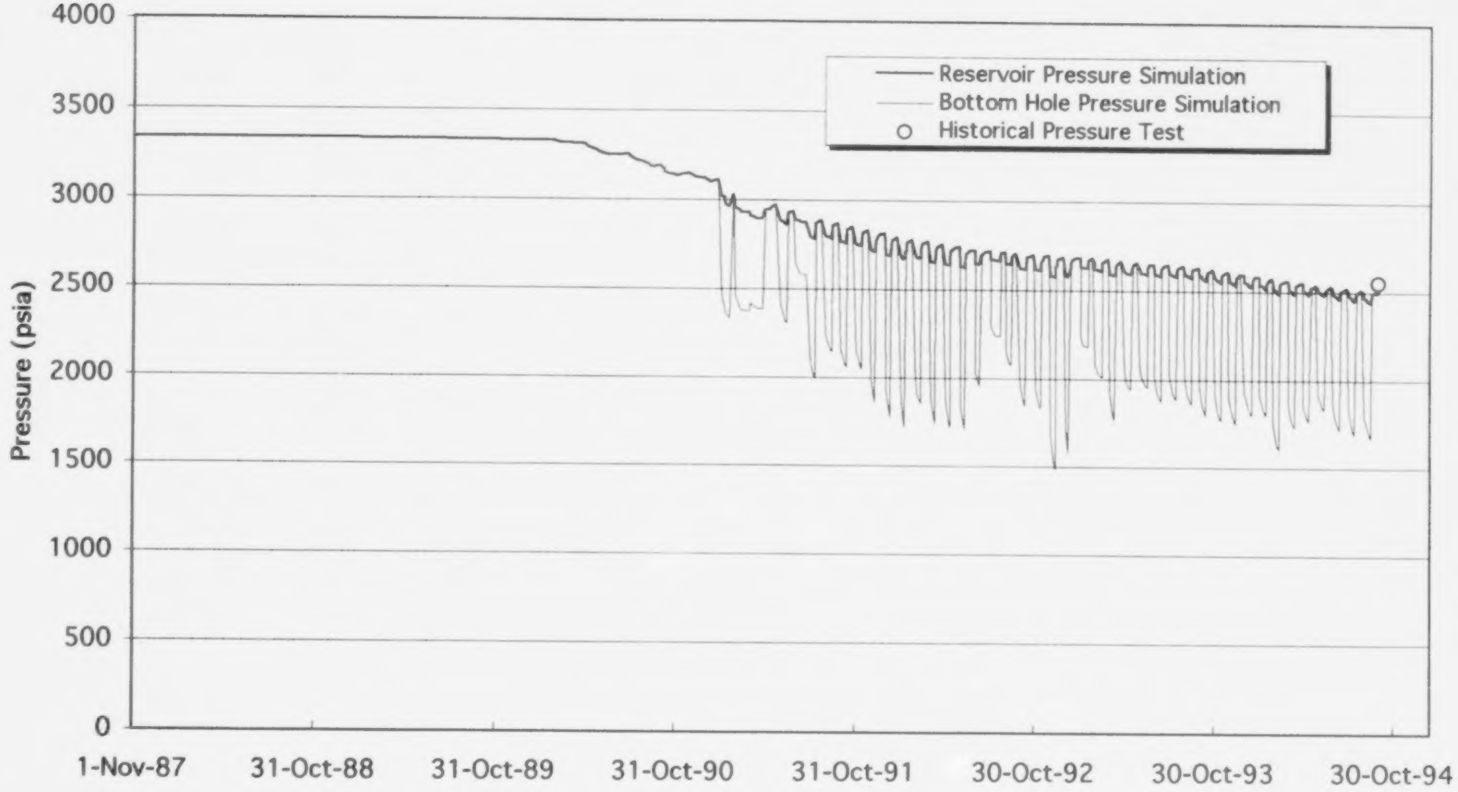

Figure 4.2(f): Pressure History Match (08-14-37-8W5)

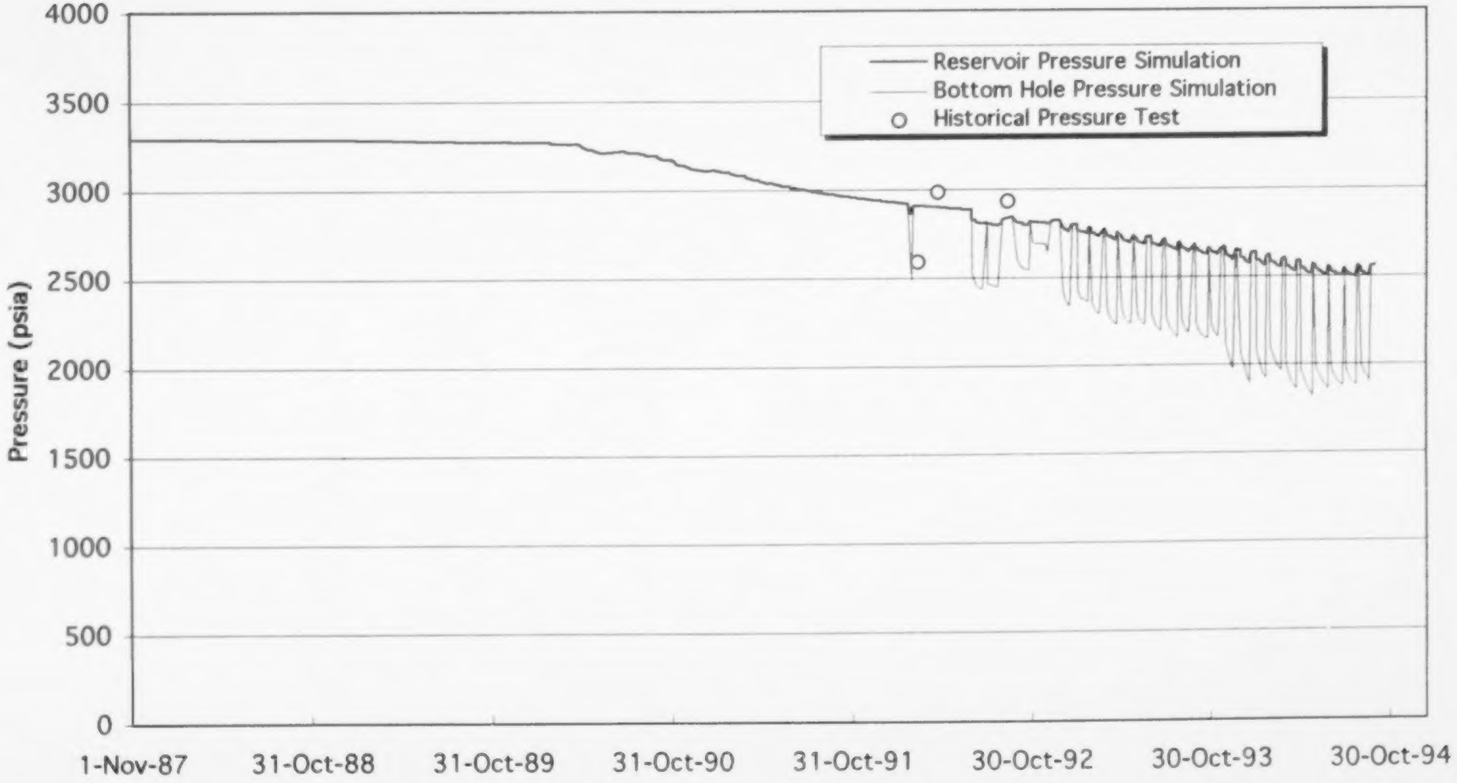

Figure 4.2(g): Pressure History Match (08-18-37-7W5)

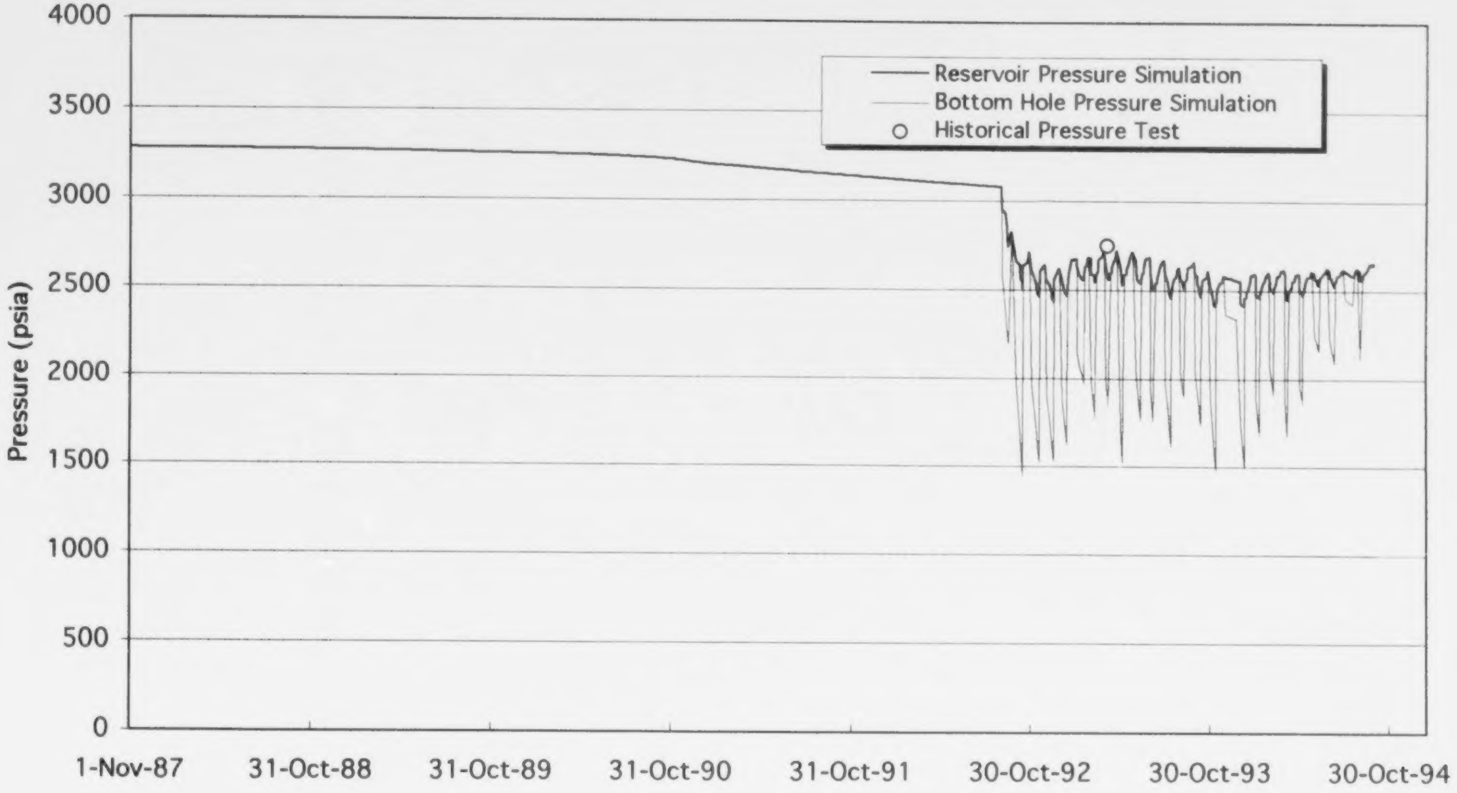

Figure 4.2(h): Pressure History Match (16-08-37-7W5)

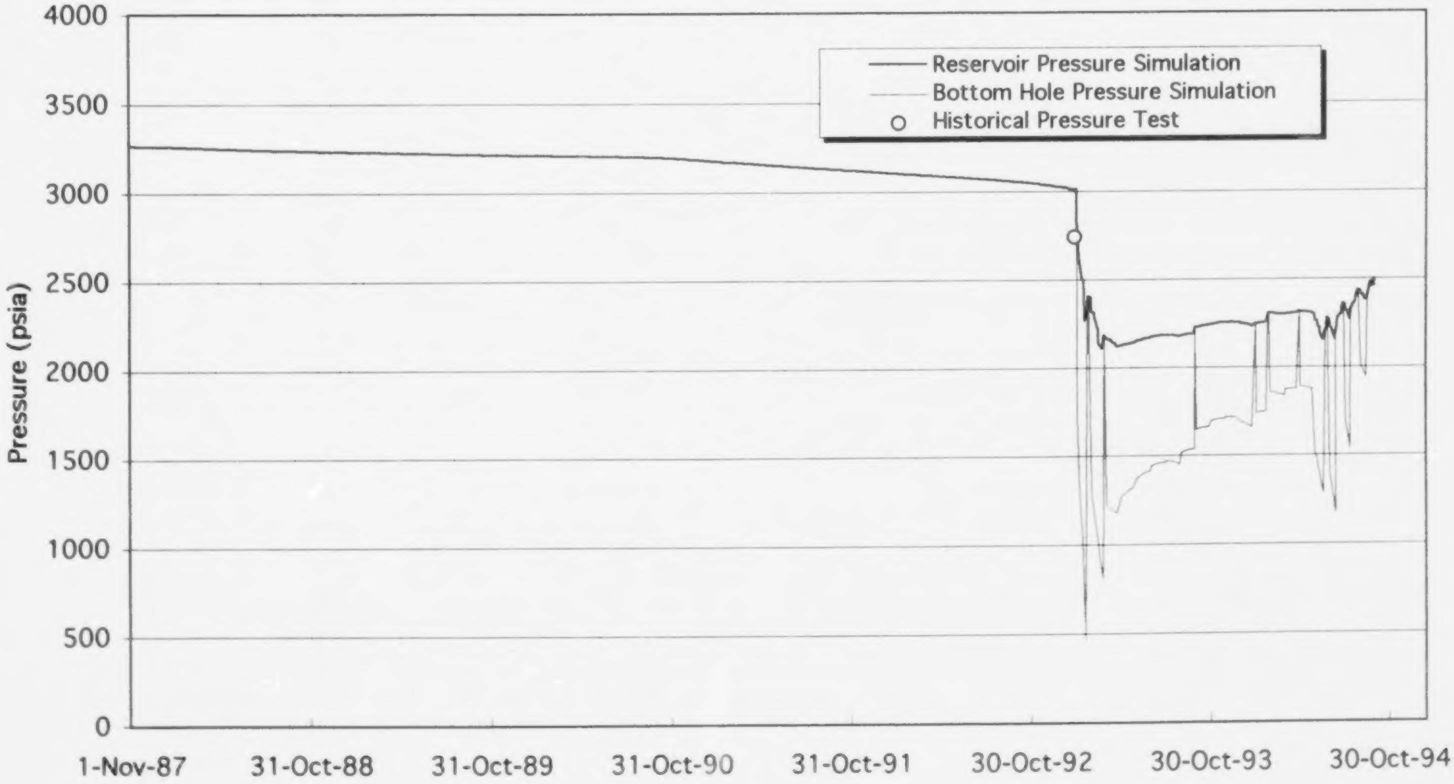

Figure 4.2(i): Pressure History Match (14-09-37-7W5)

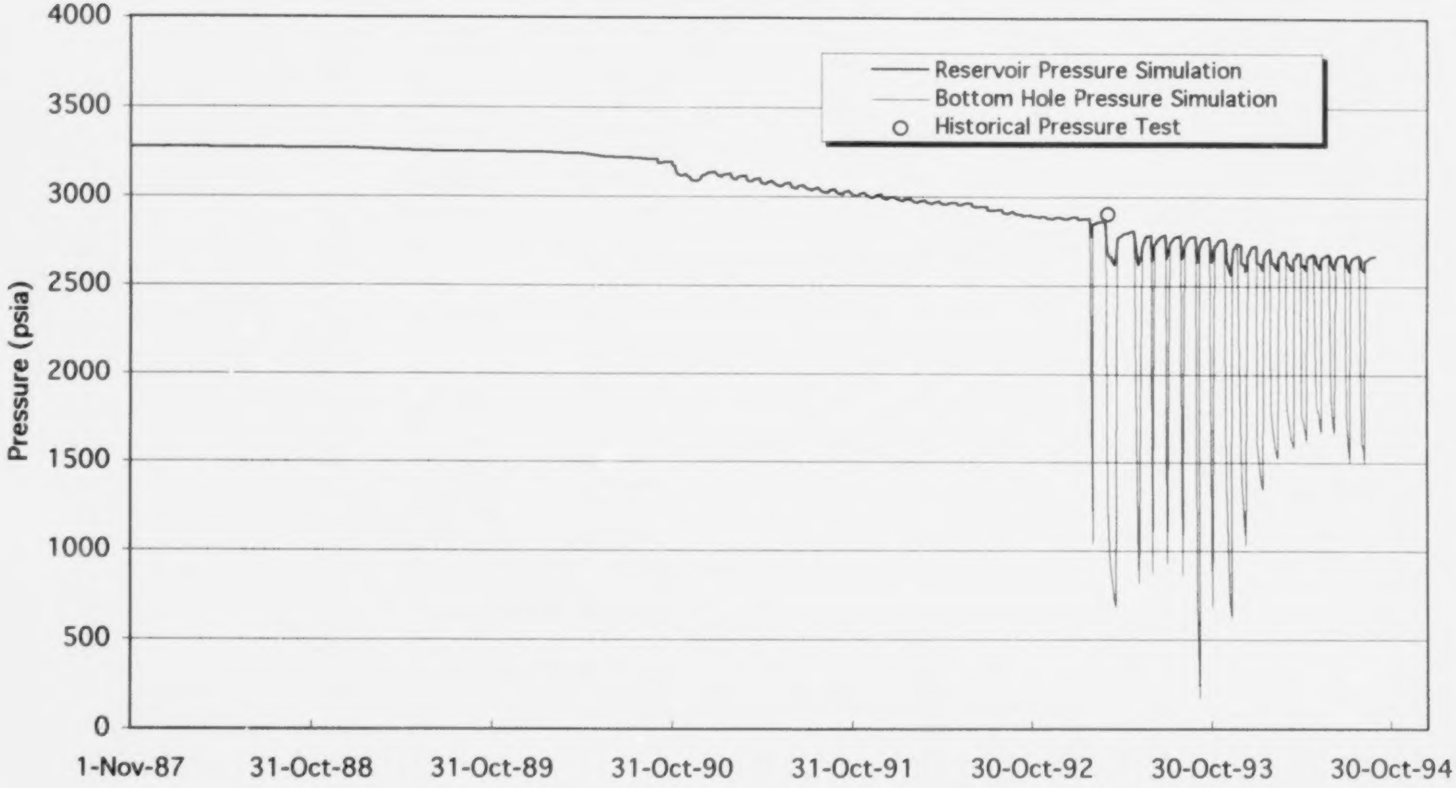

Figure 4.2(j): Pressure History Match (08-17-37-7W5)

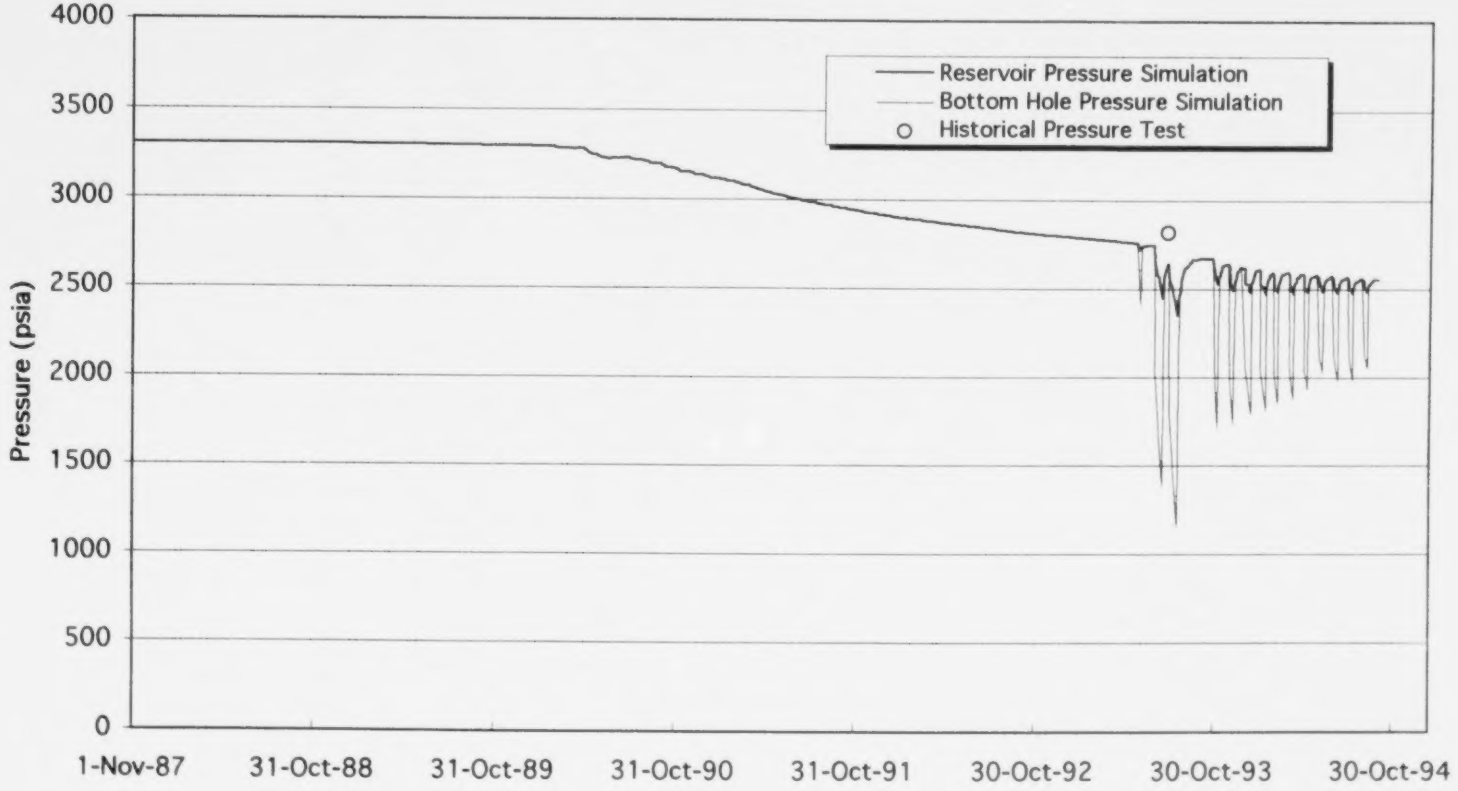

Figure 4.2(k): Pressure History Match (14-07-37-7W5)

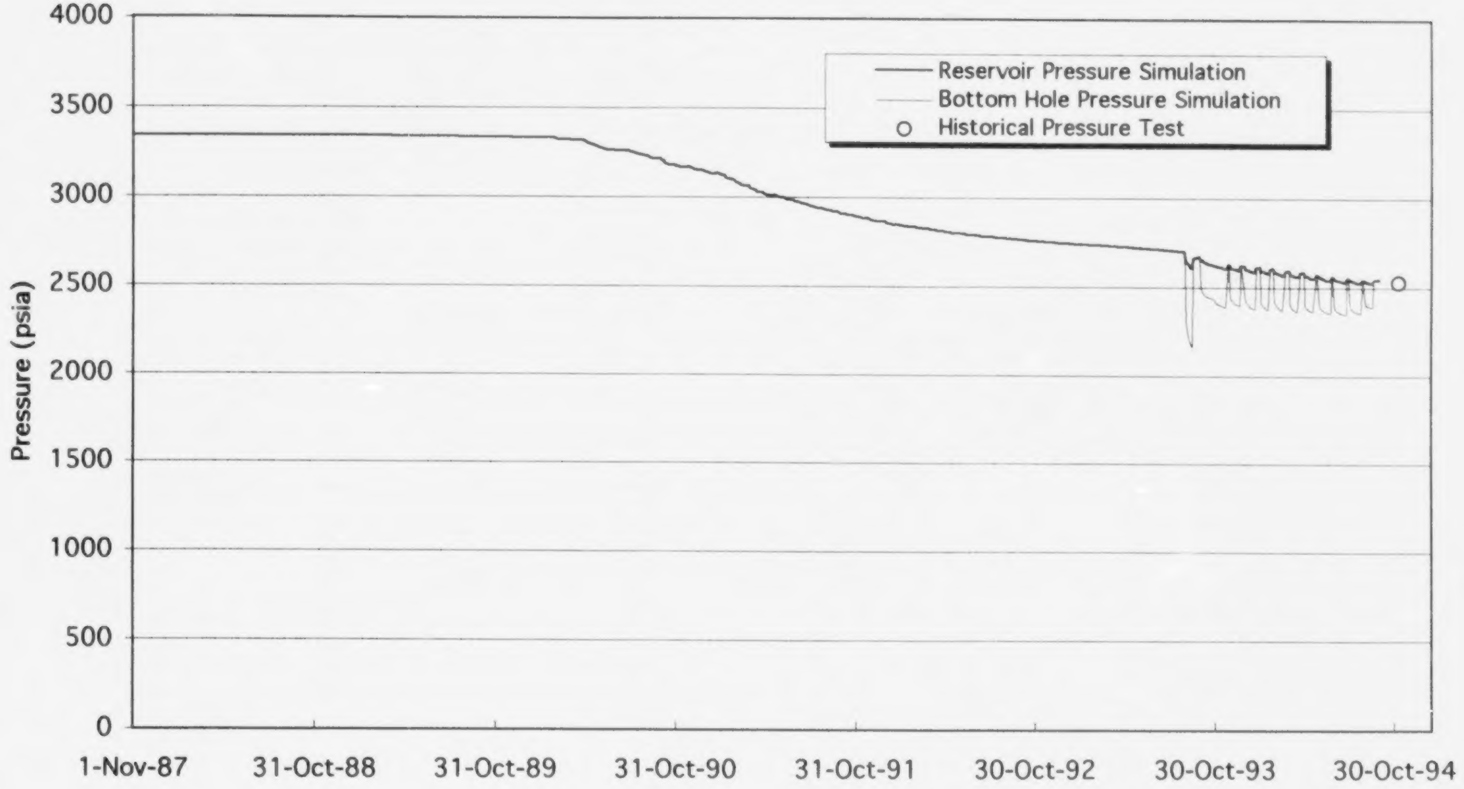

Figure 4.2(l): Pressure History Match (14-12-37-8W5)

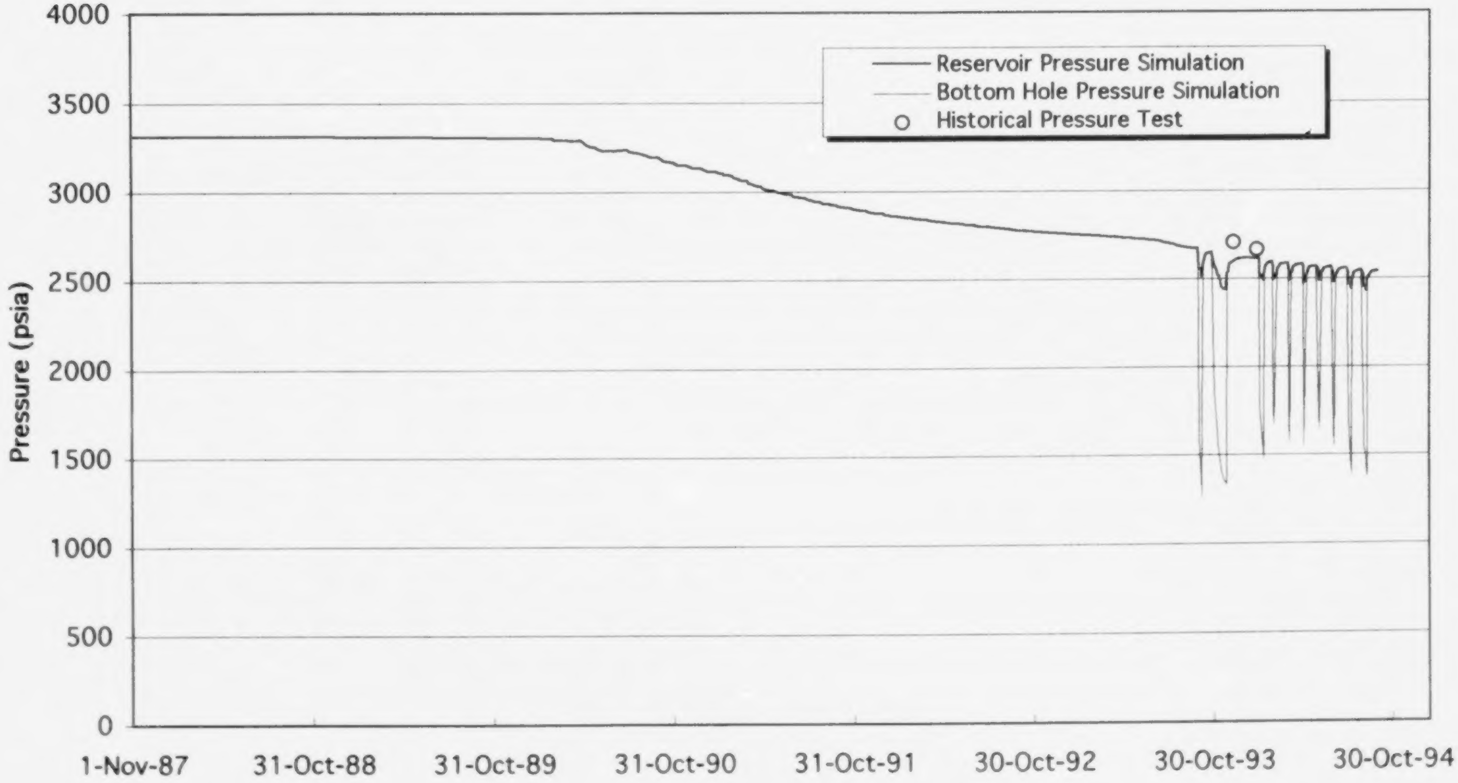

Figure 4.2(m): Pressure History Match (16-12-37-8W5)

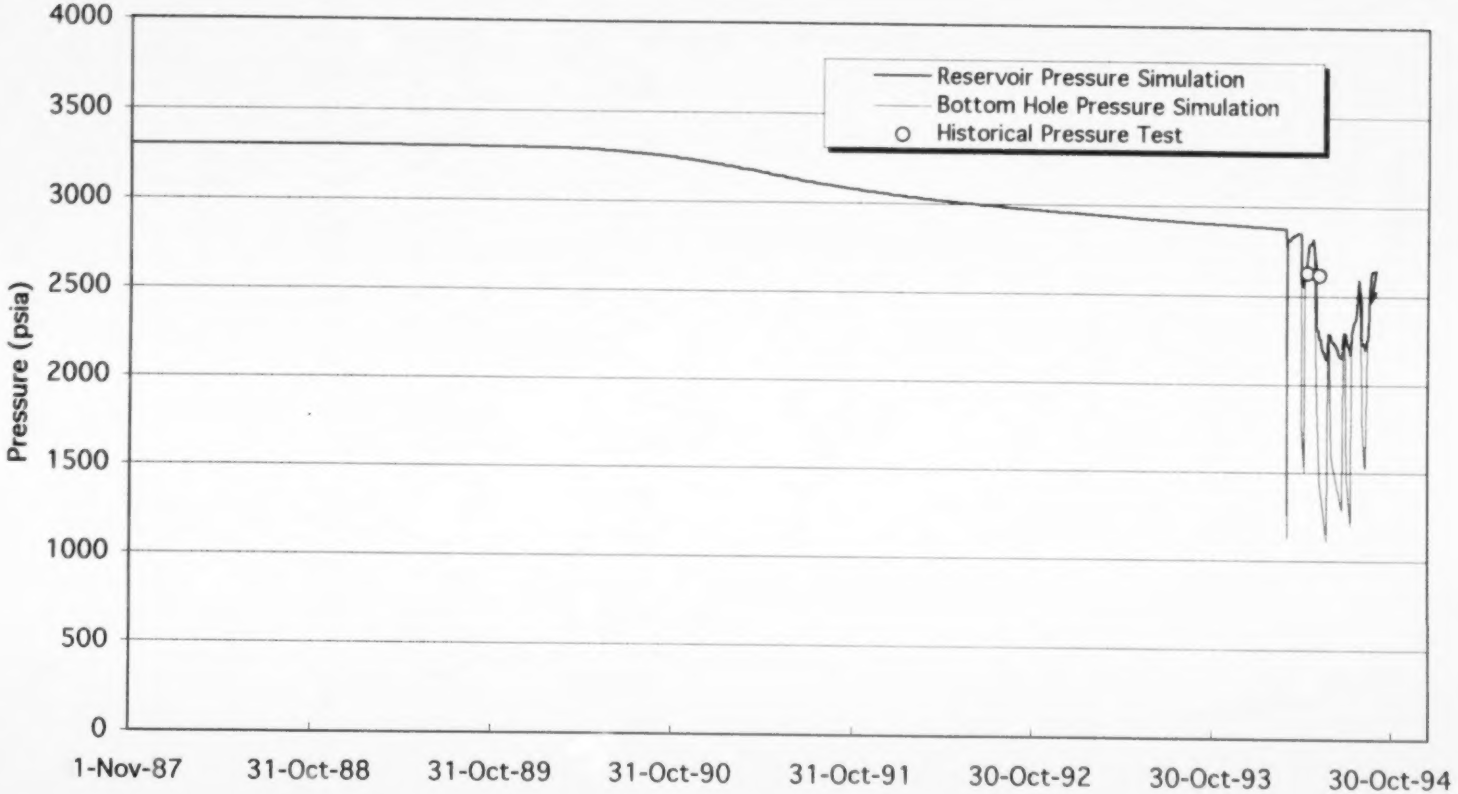

Figure 4.2(n): Pressure History Match (08-07-37-7W5)

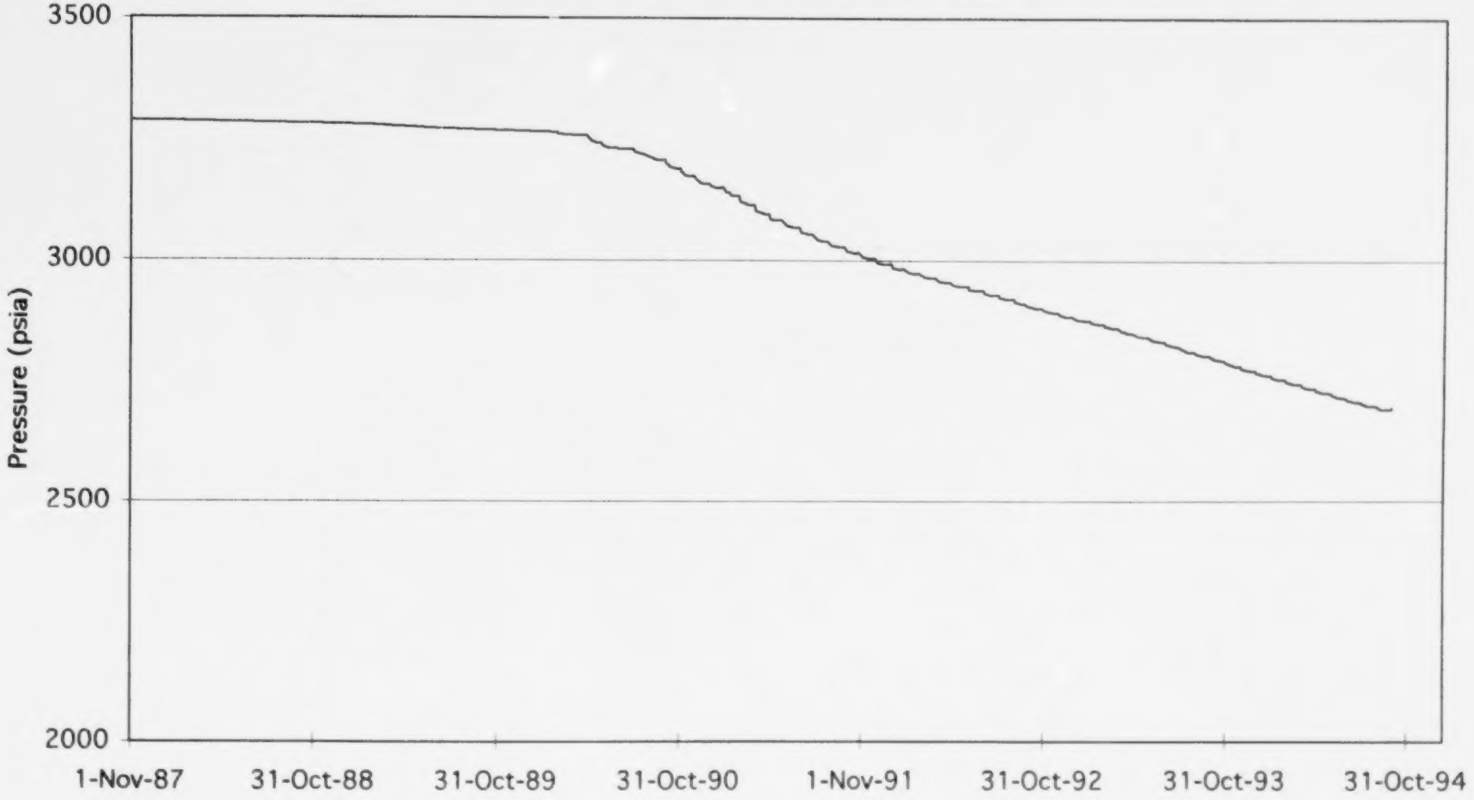

Figure 4.3(a): Average Reservoir Pressure (Simulation)

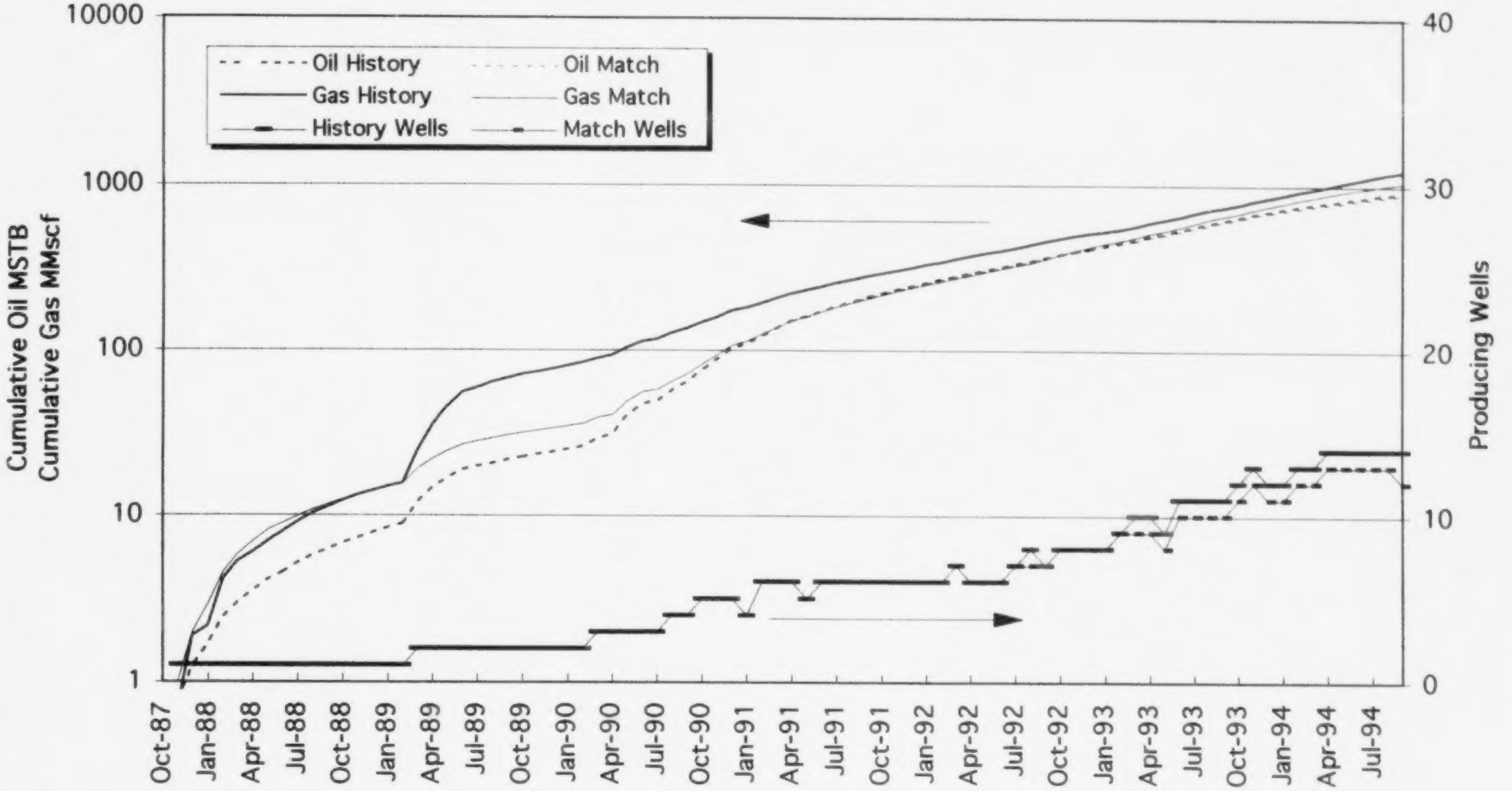

Figure 4.3(b): Pool Cumulative Production History Match

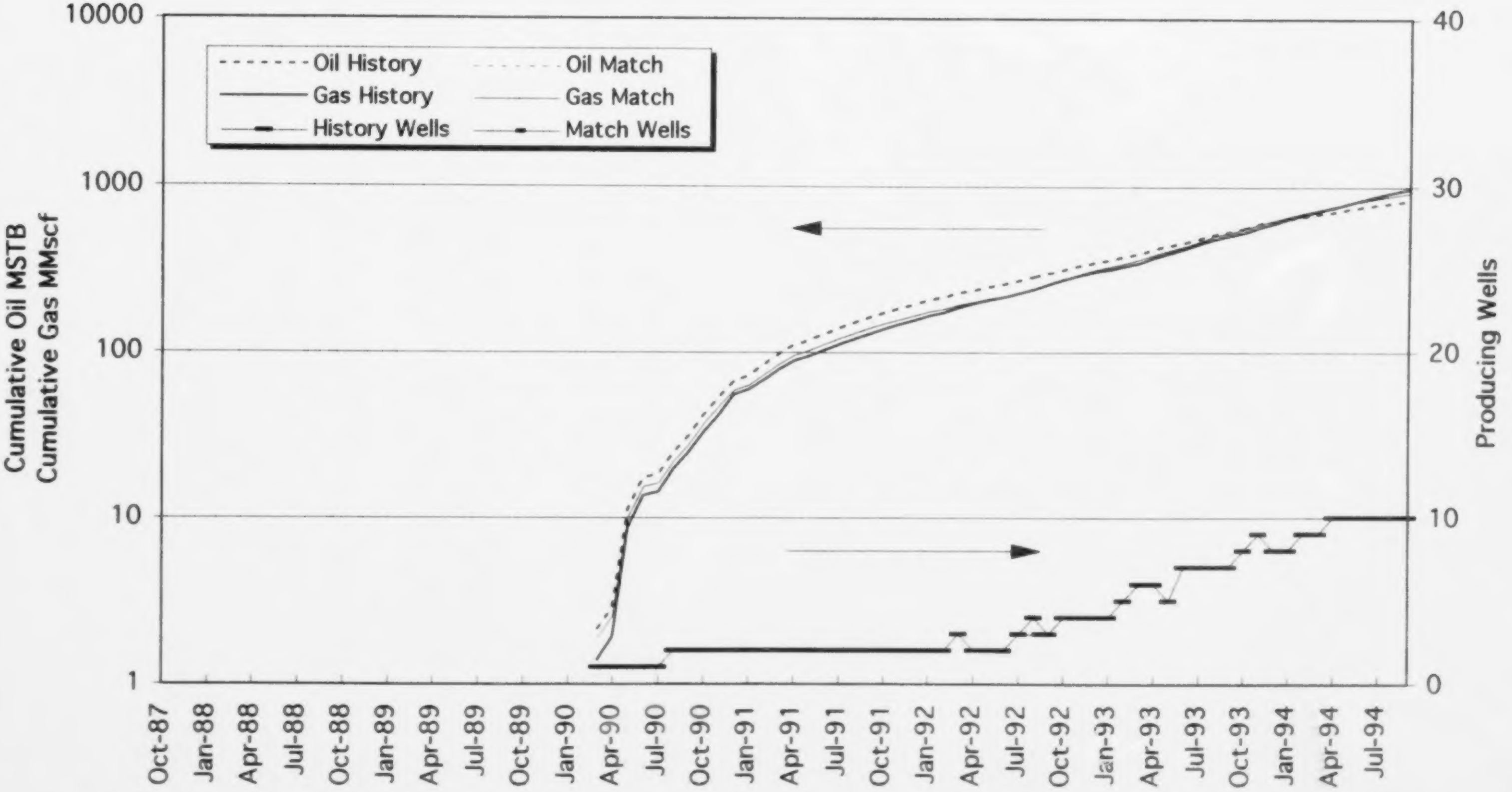

Figure 4.3(c): Pool Cumulative Production History Match

(Excluding 16-09-37-7W5 and 06-15-37-7W5)

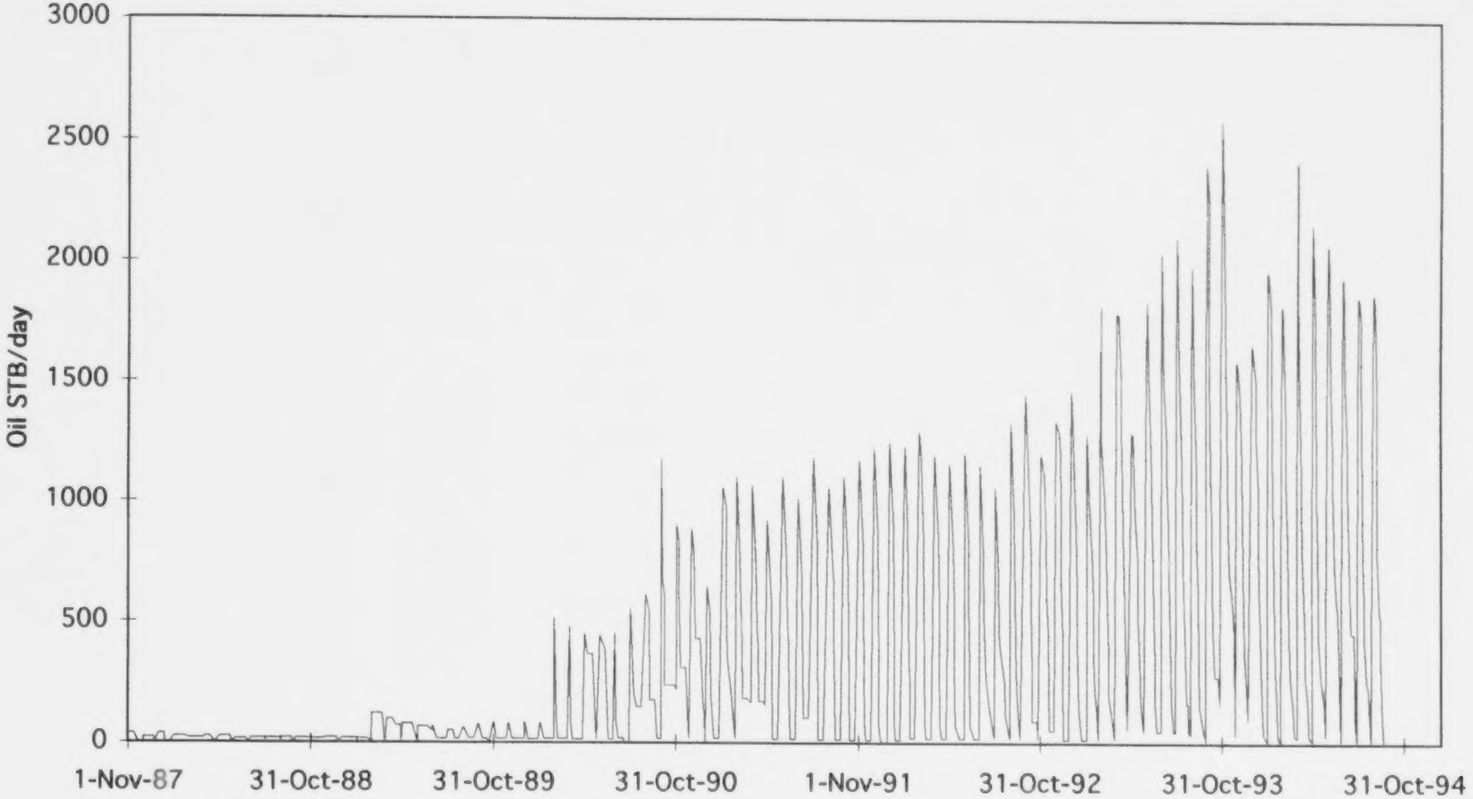

Figure 4.4(a): Pool Oil Production Rate (Simulation)

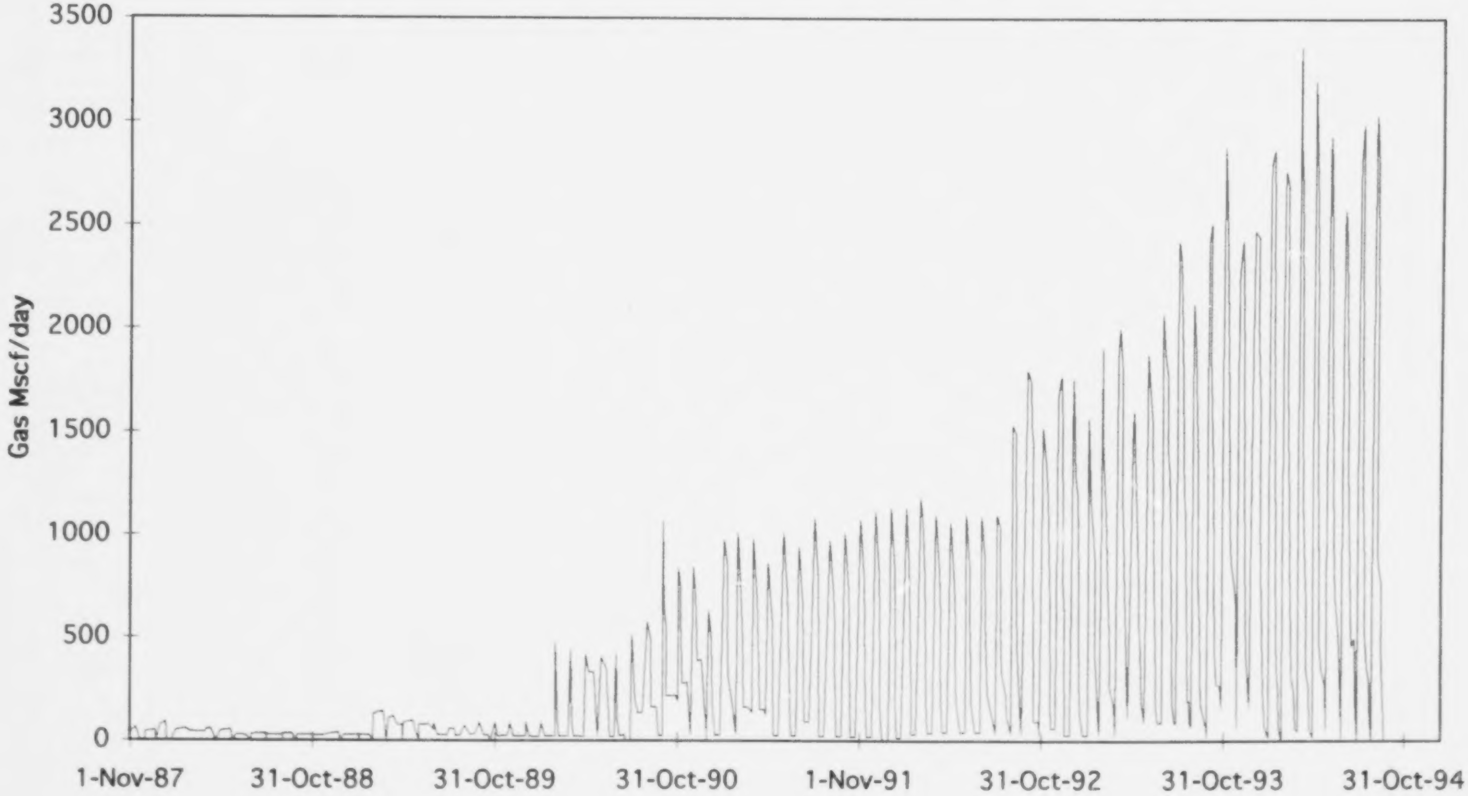

Figure 4.4(b): Pool Gas Production Rate (Simulation)

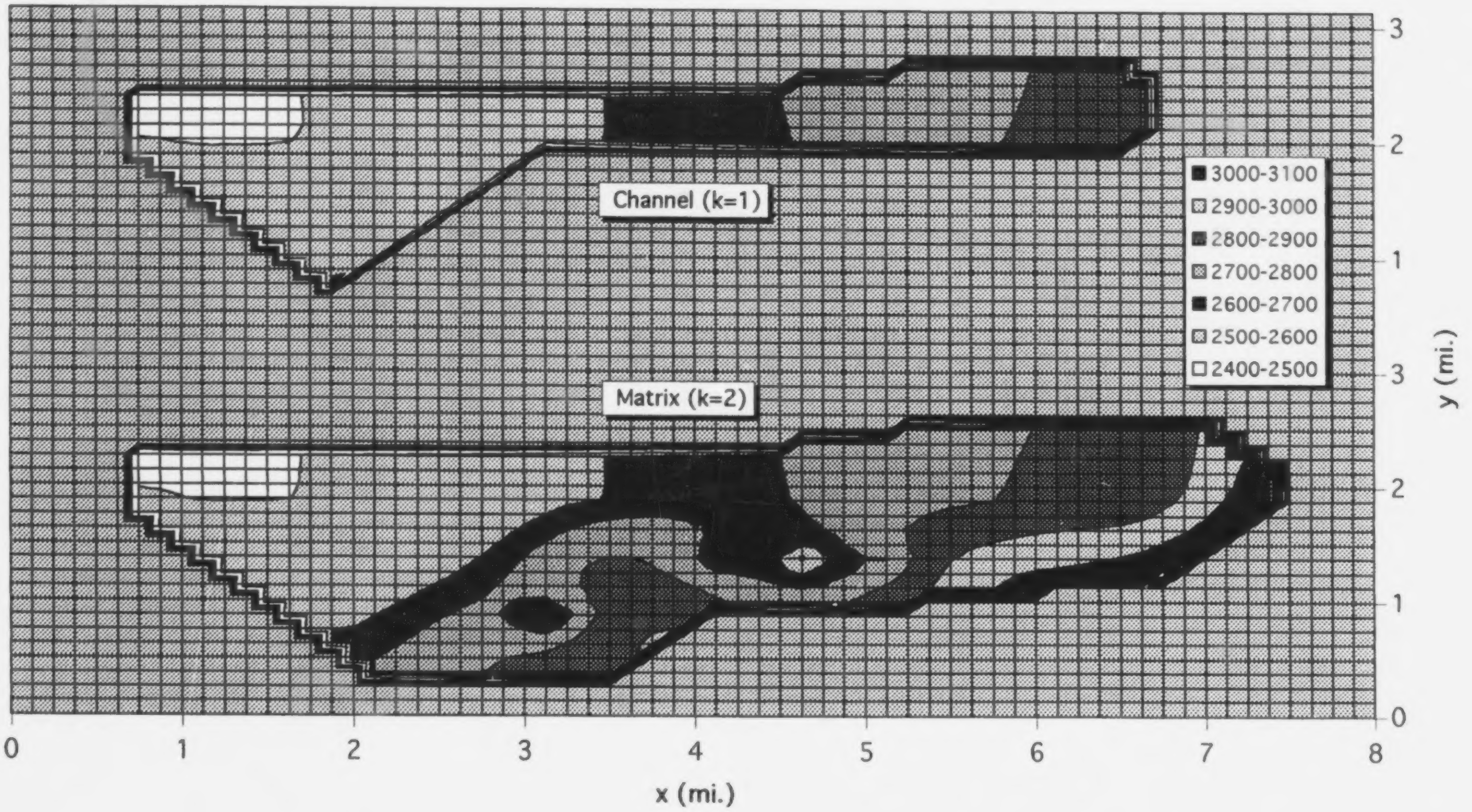

Figure 4.5(a): History Match (Oct-94) Pressure p (psia)

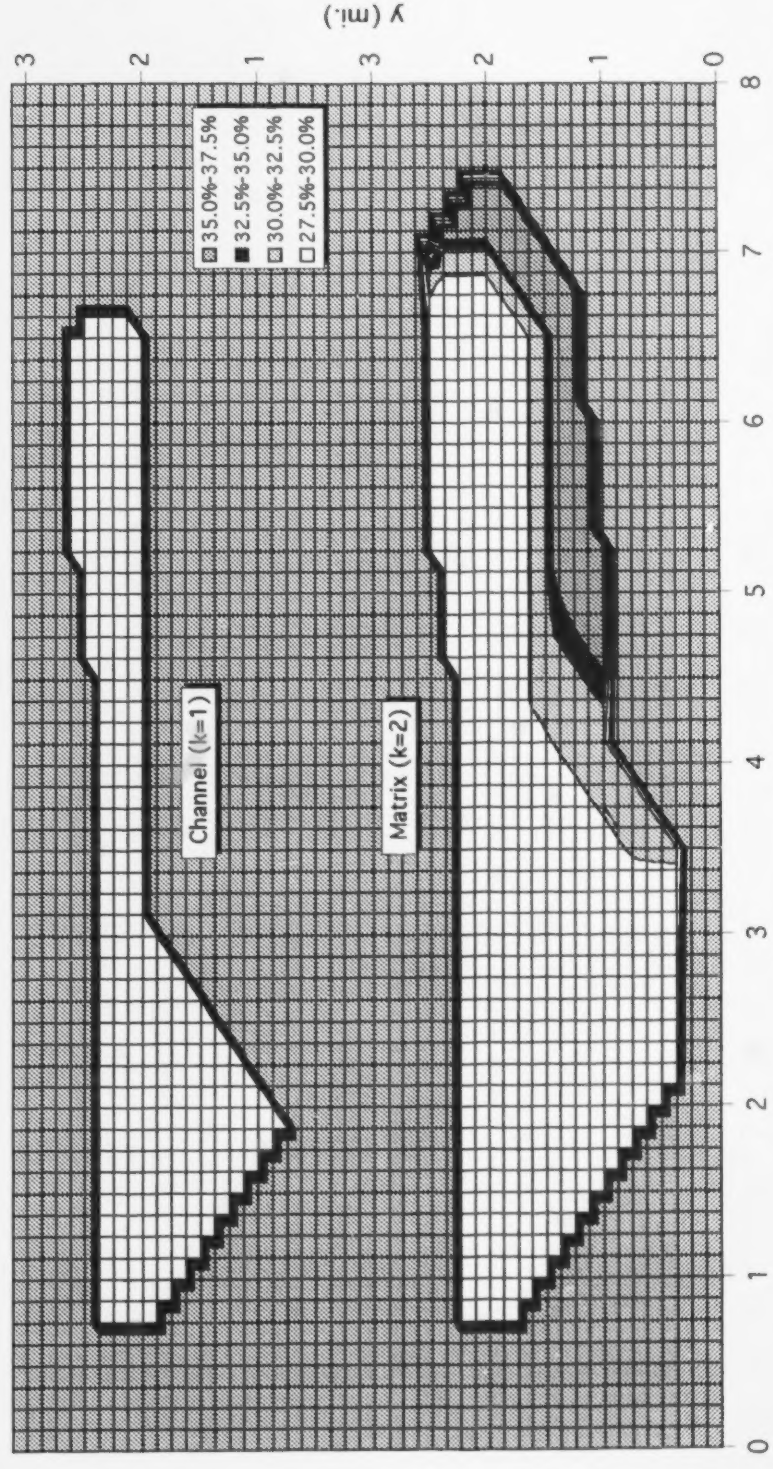

Figure 4.5(b): History Match (Oct-94) Water Saturation S_w

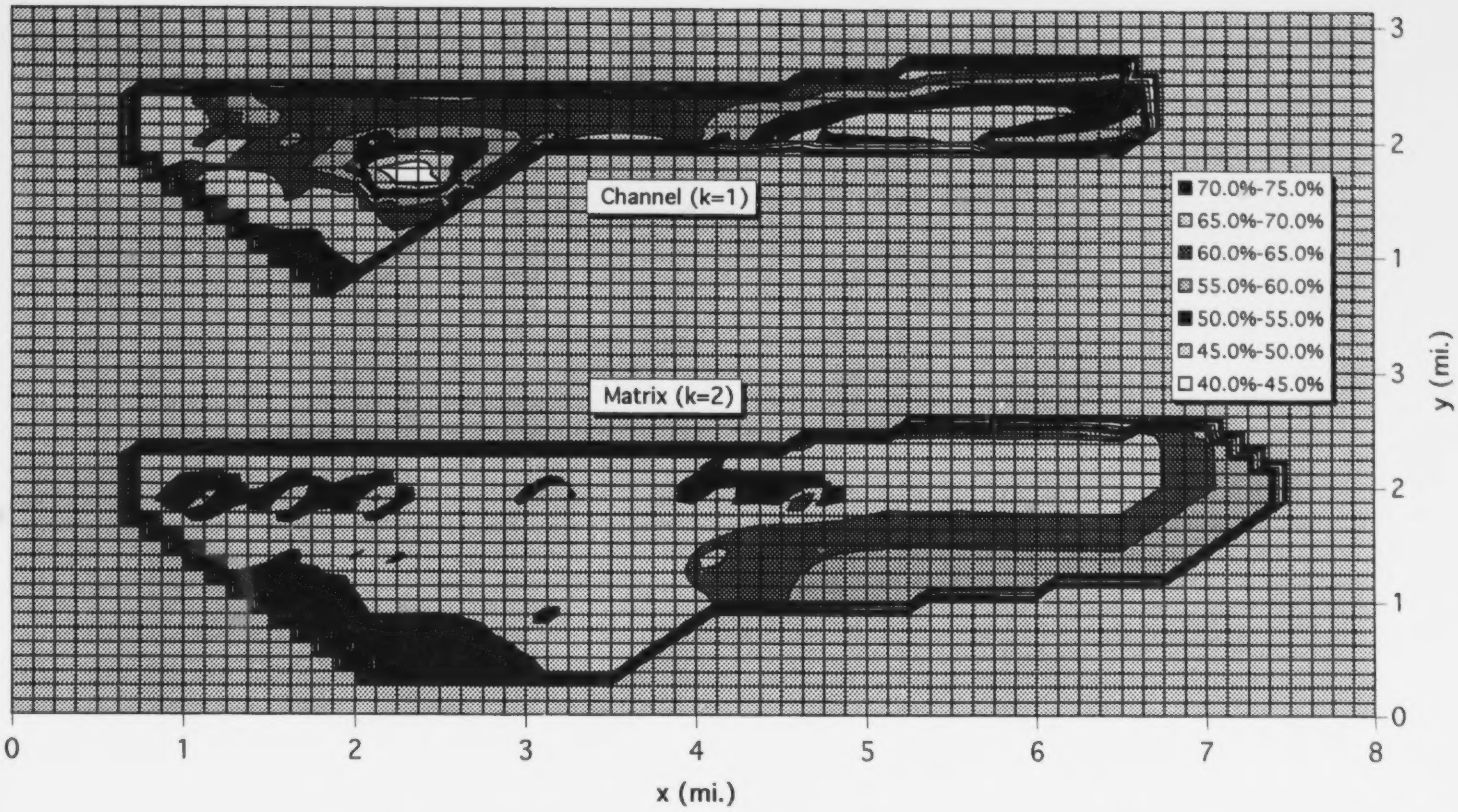

Figure 4.5(c): History Match (Oct-94) Oil Saturation S_o

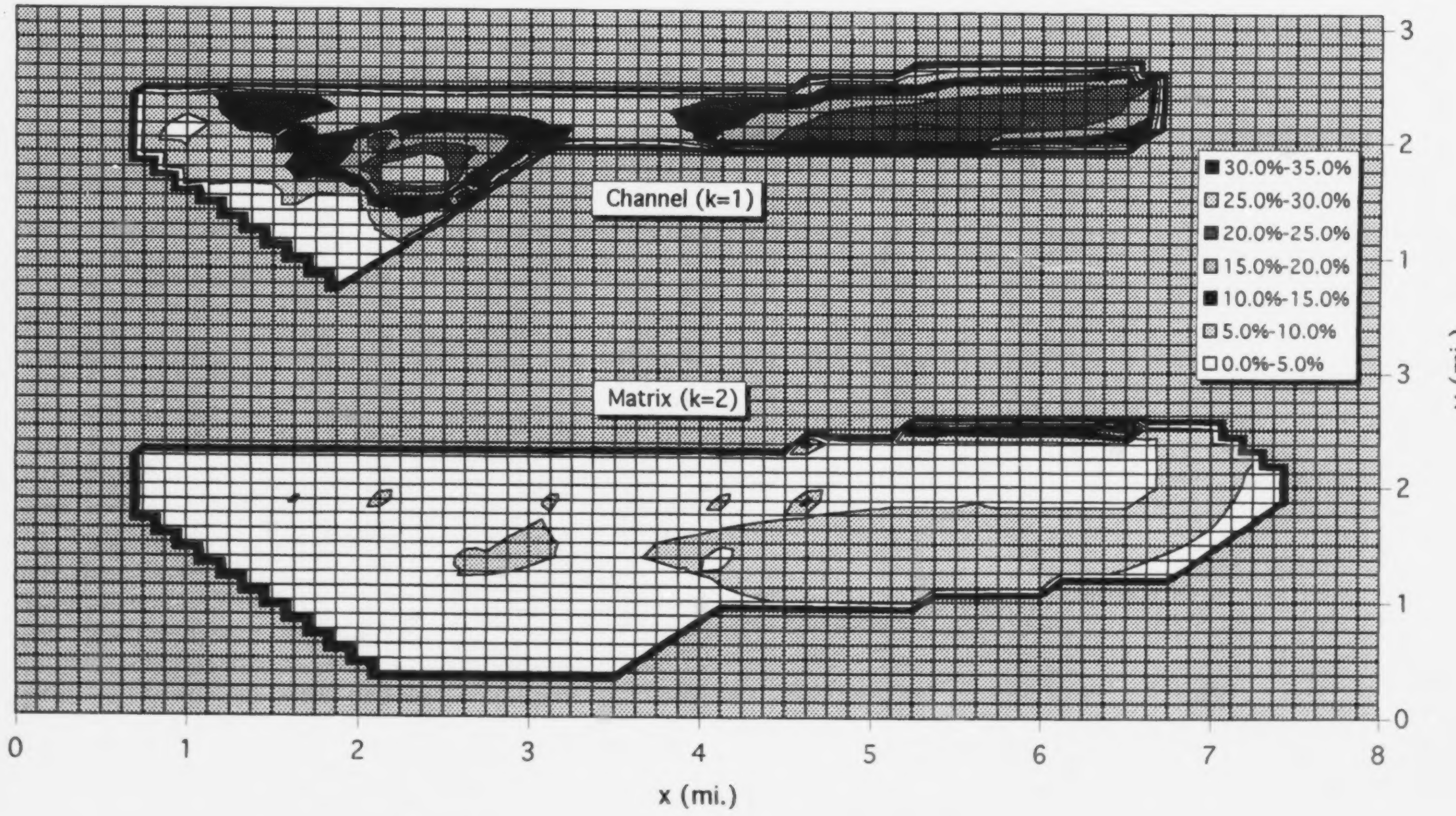

Figure 4.5(d): History Match (Oct-94) Gas Saturation S_g

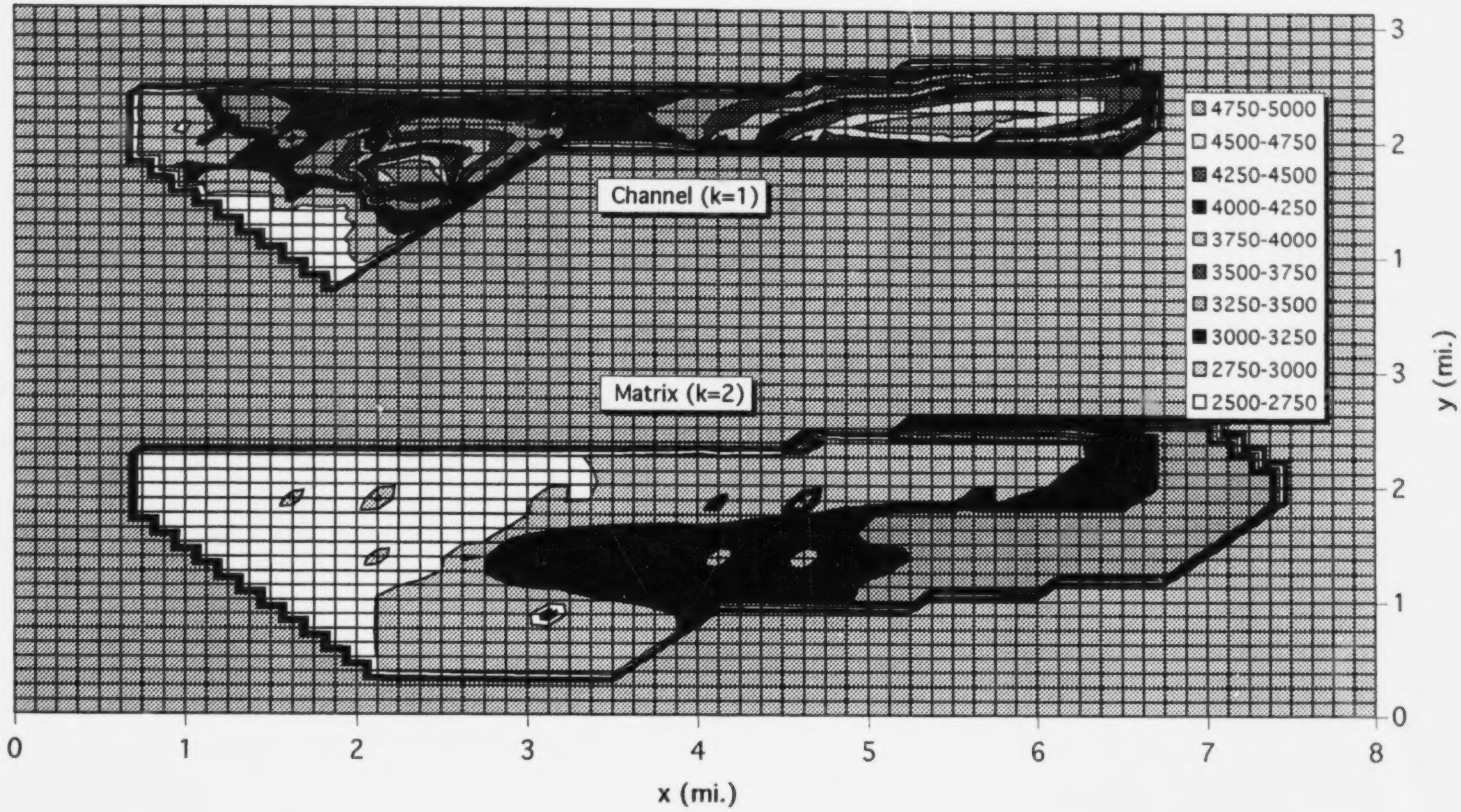

Figure 4.5(e): History Match (Oct-94) Bubble Point p_b (psia)

Chapter 5: Primary Forecast

5.1 Primary Controls

Wells 06-15-37-7W5 and 16-09-37-7W5 in the developing gas cap are excluded from the forecast and designated as shut in. No new wells are scheduled for primary operations. The model chooses not to overproduce under primary MRL regulations. All produced gas is flared rather than gathered. Primary operations assume that the current single well MRL and GOR will continue for another year. The high gas-oil ratio producer 14-09-37-7W5 at the source of the pressure disturbance is scheduled to be shut-in at the end of that year. The remaining wells are then reclassified under a new block MRL status and reassigned with an aggregate primary MRL=1320 STB/day. The pooled aggregate MRL is based on the sum total of original[16] single well MRLs. The current single well GOR is applied to the new pooled aggregate (GOR=1.129 Mscf/STB). Individual producers are designated to be permanently shut in if the oil rates fall below 10 STB/day or the gas-oil ratio rises above 50 Mscf/STB. Primary production is scheduled to terminate after 13 years of simulated time which completes a 20 year recovery life on 1-Oct-2007.

An accounting system was used to regulate oil and gas production. This system implemented the primary control policy described in Section 3.7. Explicit time steps were set to coincide with individual well production cycles. Wells were toggled on and off between maximum admissible rates established by well productivity (Eqns 3.7-3.9) and no-flow shut-in states. Monthly production accounts were accumulated for each well to satisfy single well MRL=88 STB/day and GOR=1.129 Mscf/STB regulatory constraints. All producing wells were turned on and monthly production counters set to zero at the beginning of each monthly cycle. Automatic time step control used a Courant number ($N_{Courant}$=.25) and bounded base time steps between 5-10 days to ensure numerical stability. Maximum changes over each timestep for reservoir pressure and phase saturation was limited to 1000 psi and 10%, respectively. Remaining oil and gas production quota bandwidths (Eqn 3.17) for individual wells were estimated at each step using the explicit well model. The minimum remaining bandwidth was selected from all wells for the new time step. Gas quotas had precedence over oil quotas and wells were toggled off accordingly. Consecutive time steps were marked by the minimum between the base time step, remaining time for the monthly accounting cycle and the remaining durations over all wells. Gas produced by individual wells over each time step was accumulated in corresponding counters. Relevant wells were toggled off and the next step initiated. Each well tracked different monthly production hours. Cycle-averaged oil, gas and water rates were calculated for each well by dividing accumulated monthly production accounts by the corresponding hours of production. Cycle-averaged production rates were recorded for the current month at the end of the monthly cycle. Calendar time was used for each month. Instantaneous aggregate pool production rates and average reservoir pressure were recorded at each time step. Instantaneous bottomhole pressures for each well were also recorded at each time step. The actual simulation time[17] on the available hardware grew proportionately with an overwhelming number of time steps when all production wells were online and tracked separately. A simplification was considered for the pooled production constraint which became effective after the first year of primary production forecasting. This simplification used the same accounting system to calculate one monthly lumped cycle for all pooled wells, with explicit timing based on aggregate maximum admissible production rates. Relevant wells were simultaneously, and collectively, toggled on and off, once a month. Individual producers were permanently shut in when oil production rates fell below 10 STB/day or the gas-oil ratio exceeded 50 Mscf/STB. The aggregate production quota remained constant so that production slack from shut-in wells were redistributed to those wells still in operation.

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[16] The aggregate MRL also includes the isolated producer 08-08-37-7W5 in Chedderville Viking "B". The model assumes that the low-rate producer is effectively shut in and does not interact with Viking "A" wells.

5.2 Primary Simulation

Figures 5.1(a)-(l) shows monthly production forecasts for the twelve wells appointed for primary operation. Most wells continue to produce below rated pump capacity (500 STB/day). Production is limited by the flowing bottomhole pressure constraint. Figure 5.1(g) shows the scheduled shut in of 14-09-37-7W5 at the end of first year. This well was producing continuously without bang-bang control at the time of shut in (Oct-95). The change from single well MRL to block MRL (Oct-95) is observed to shift cycle-averaged production rates and hours of operation. The block MRL reclassification with aggregate control change-over leads to a global increase and redistribution of production quotas within the pool. Most wells react with a sudden jump to longer hours of monthly operation. Some wells react with short-lived increases in oil production as a result of transient pressure disturbances. Figure 5.1(l) shows a decrease in production hours for 08-07-37-7W5 with a sustained increase in daily oil rates. Gas production in most wells is observed to peak within two to three years and rapidly decline thereafter. Wells represented in Figures 5.1(a),(b) and (d) are shut in prematurely (Oct-02) as a result of oil rates falling below the 10 STB/day cutoff. The reallocation of production slack to remaining wells are marked by longer production hours. The increase in production triggers a gas-oil ratio crossover from undersaturated to saturated bottomhole conditions for 08-07-37-7W5 as shown in Figure 5.1(l). Figures 5.2(a)-(l) shows the predicted response in instantaneous bottomhole pressures. The flowing bottomhole pressure spikes represents the cyclic response to bang-bang rate controls. The flowing bottomhole pressures reach the set point floor (p_{wf}=800 psia). Most wells exhibit a linear decline trend in static bottomhole pressure. Figure 5.2(g) shows the increase in static pressure as gradual fluid influx from tight porous media stabilize pressure gradients about 14-09-37-7W5.

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[17] Actual reservoir simulation time on a Power Macintosh 6100/60 for the branched production forecast was one hundred hours of continuous CPU time. The final simulation run was performed on a Power Macintosh 8500/120 using forty hours of dedicated CPU time. These run-times correspond to the pooled accounting simplification which gave an overall time reduction factor by at least five.

Figure 5.3(a) shows a linear decline trend in average reservoir pressure. Figure 5.3(b) shows the cumulative oil and gas production predicted for the entire pool. Cumulative gas increases linearly while cumulative oil increases asymptotically. Figures 5.4(a) and (b) show the predicted instantaneous pooled oil and gas production rates, respectively. Pooled monthly production cycles over the first year correspond to sum total of individual well cycles at different rates and different duration bandwidths. Pooled cycles over the remaining years correspond to the sum total of individual well cycles with the same duration but different rates. The change-over in MRL and aggregate control (Oct-95) effects the decline trend in daily pooled oil rate. The decrease in pooled gas rate is a direct result of shutting in low oil producers (Oct-02). The decrease in pooled oil rate (Oct-02) is a result of the gas-oil ratio crossover of 08-07-37-7W5.

Figures 5.5(a)-(e) show the predicted reservoir depletion state at the end of the planned primary period (Oct-07). Pressures are distributed between 1200-1900 psia in Figure 5.5(a). No changes are observed in the water saturation distribution in Figure 5.5(b). Figures 5.5(c)-(e) show the oil saturation, gas saturation and bubble point pressure distributions. Large amounts of saturated oil still remain in the matrix rock. The gas cap has expanded throughout the reservoir. The bubble point variation is large over the whole reservoir, especially between upper and lower layers. Accumulation of free gas migrating from the lower to upper layers has dominated the high permeability channel with lighter ends of the hydrocarbon mixture (high bubble point). Continued production, migration and evolution of free gas from the bottom layer has lowered local bubble point pressures leaving heavy ends.

5.3 Primary Summary

Primary depletion forecasted large amounts of remaining oil in place at the end of the planned primary life. The current state of operation had historically recovered 0.89 MMSTB over seven years of production. The original oil in place was estimated as 25.4 MMSTB in the reservoir model. Predicted remaining recovery was 1.05 MMSTB to give a forecasted primary recovery factor of 7.7%. Low primary recovery factors 5%-15% are characteristic of solution gas drive from Alberta light to medium density oil pools (CIM Petroleum Society Monograph No. 1 1994). The low primary oil recovery forecasted for this solution gas drive reservoir justifies the consideration of secondary recovery schemes for pressure maintenance by water injection or a pattern waterflood.

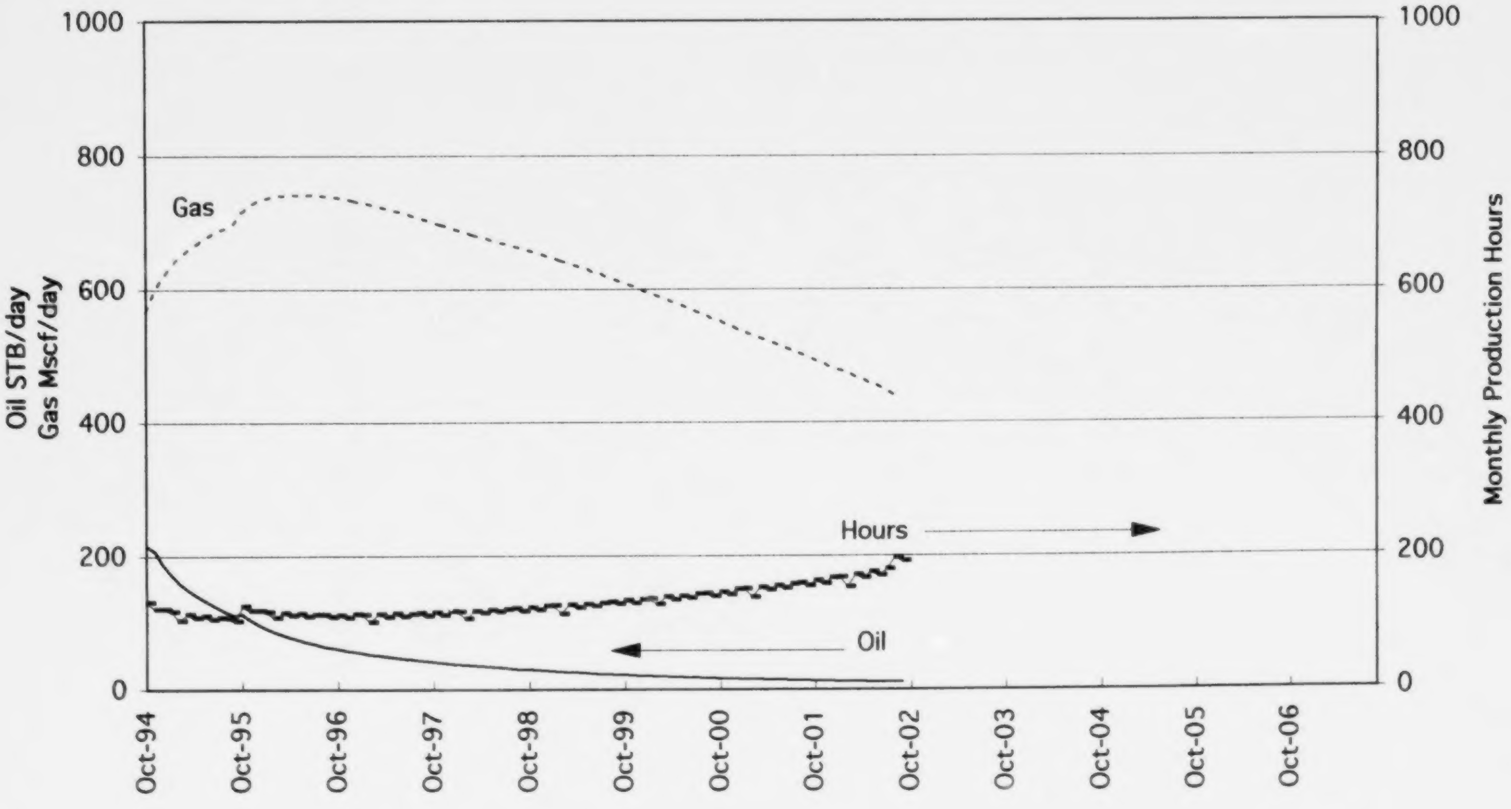


Figure 5.1(a): Primary Production Forecast (08-13-37-8W5)

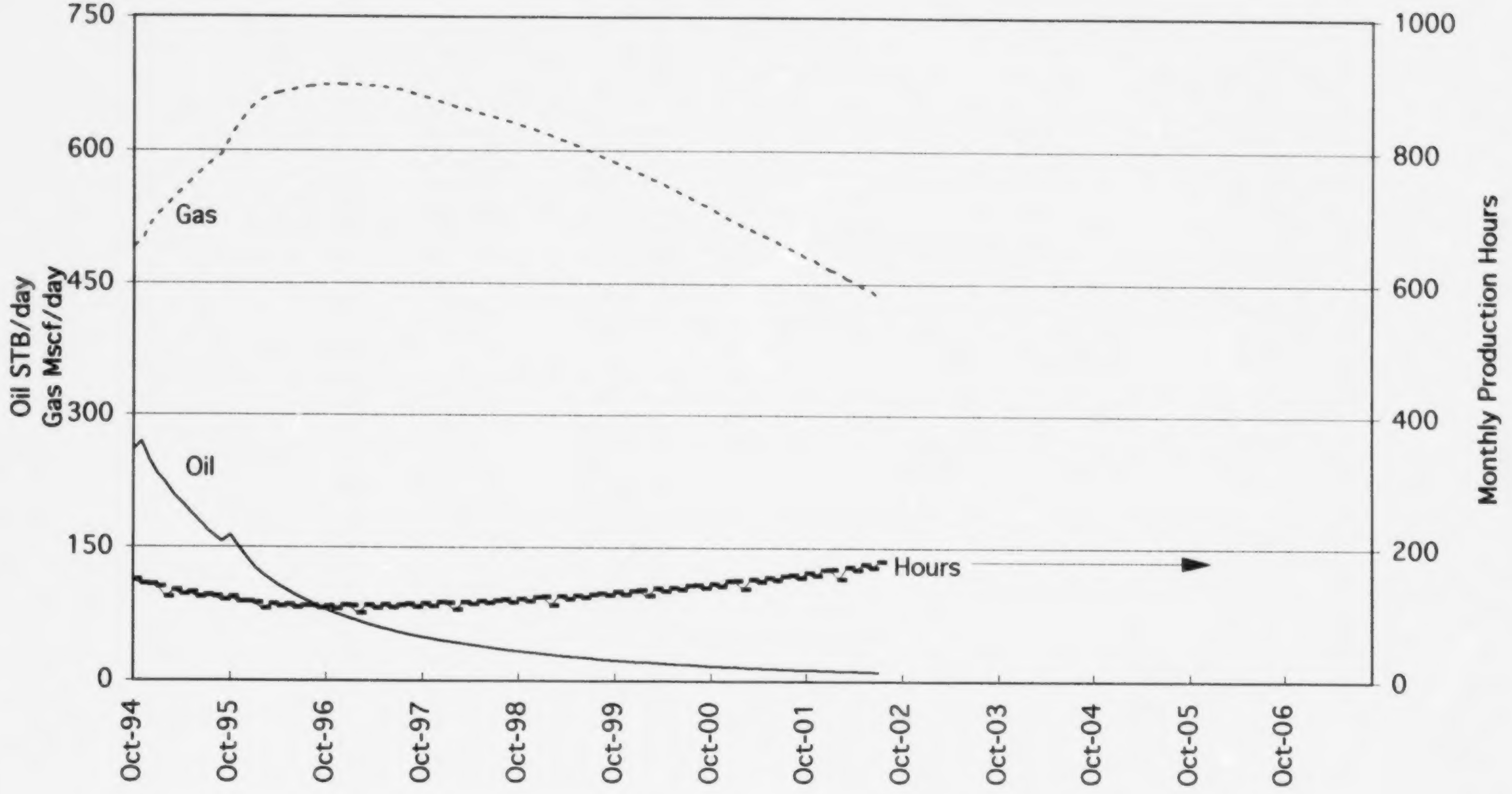


Figure 5.1(b): Primary Production Forecast (06-13-37-8W5)

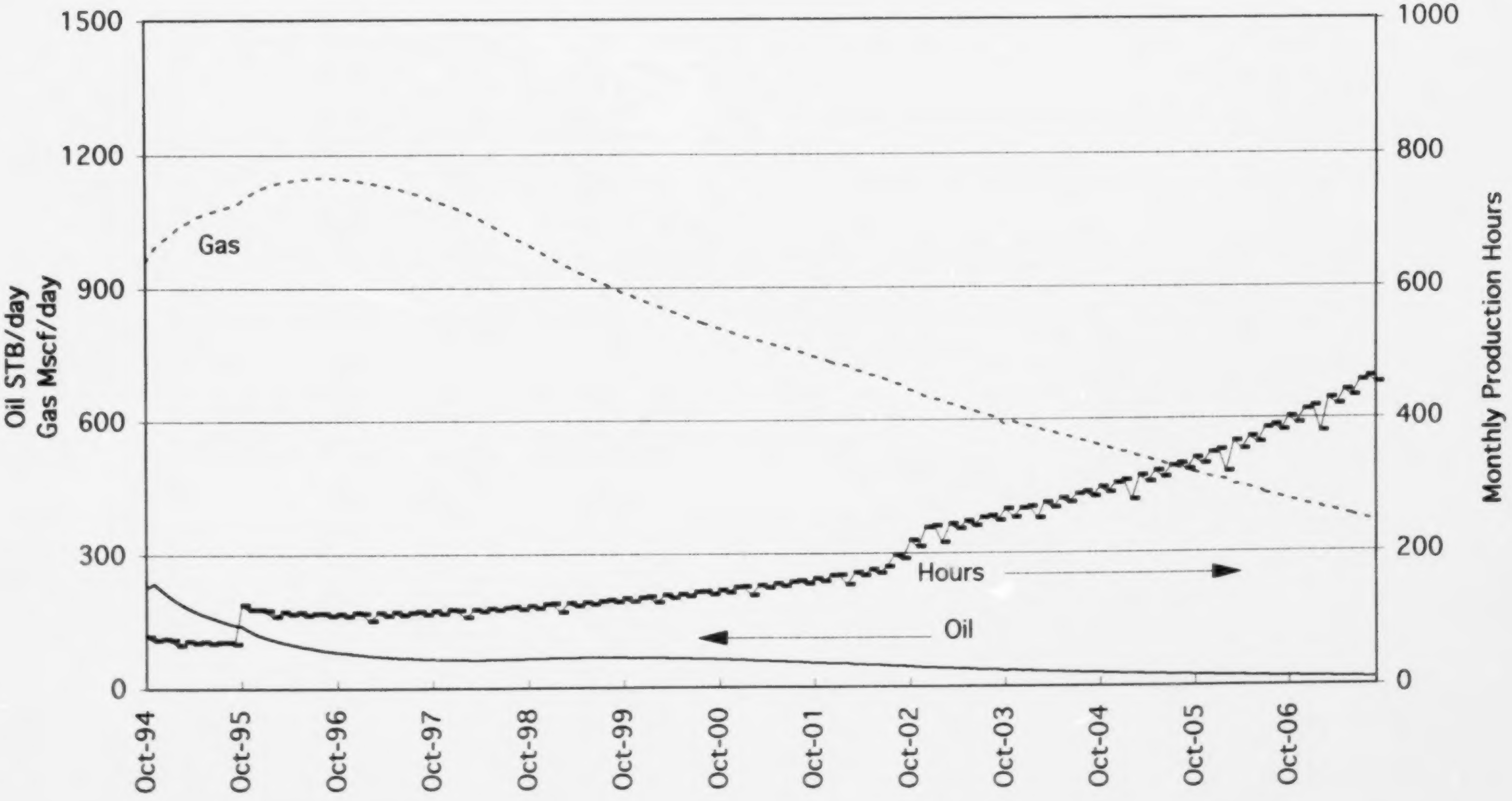


Figure 5.1(c): Primary Production Forecast (06-16-37-7W5)

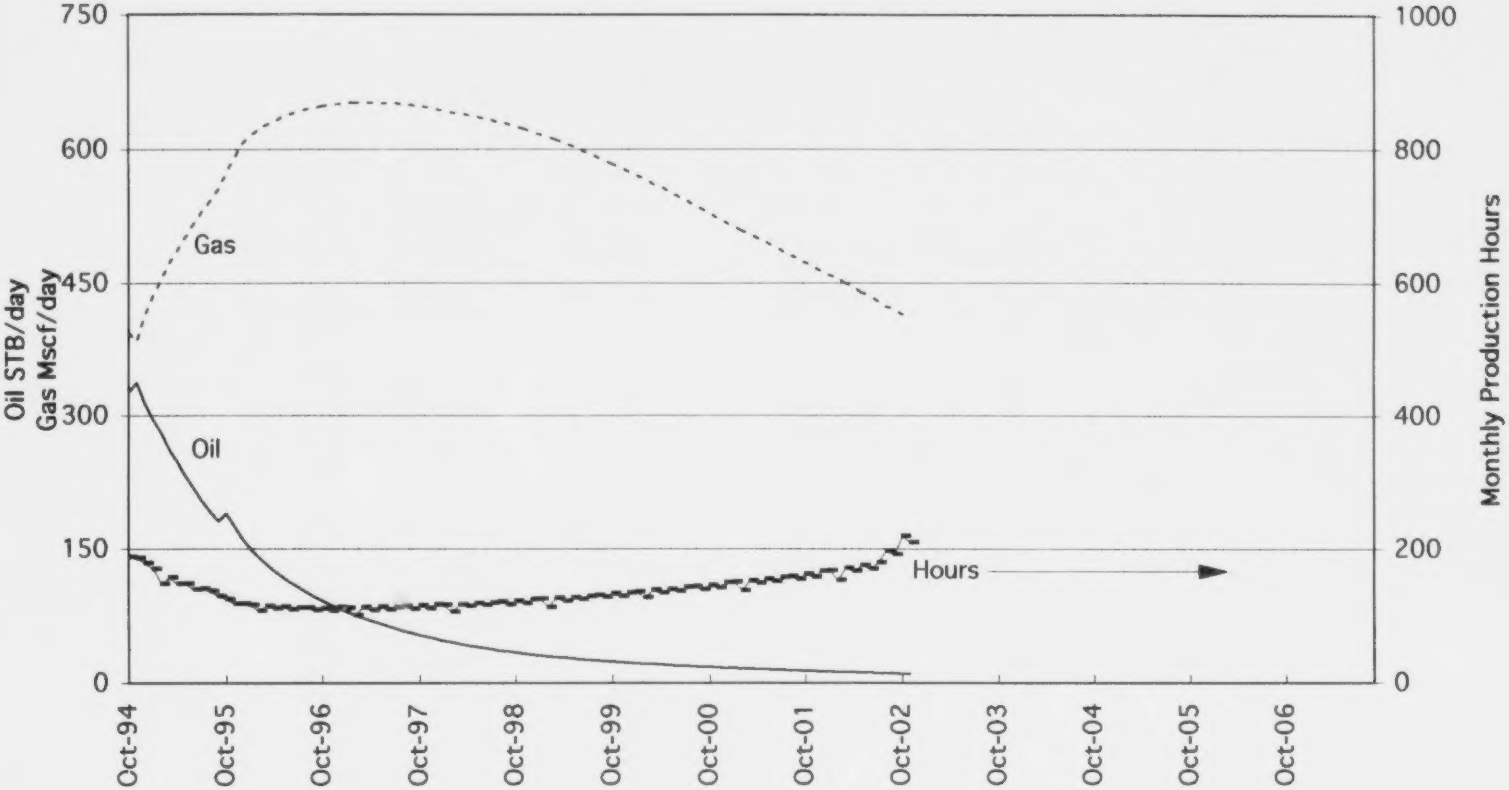


Figure 5.1(d): Primary Production Forecast (08-14-37-8W5)

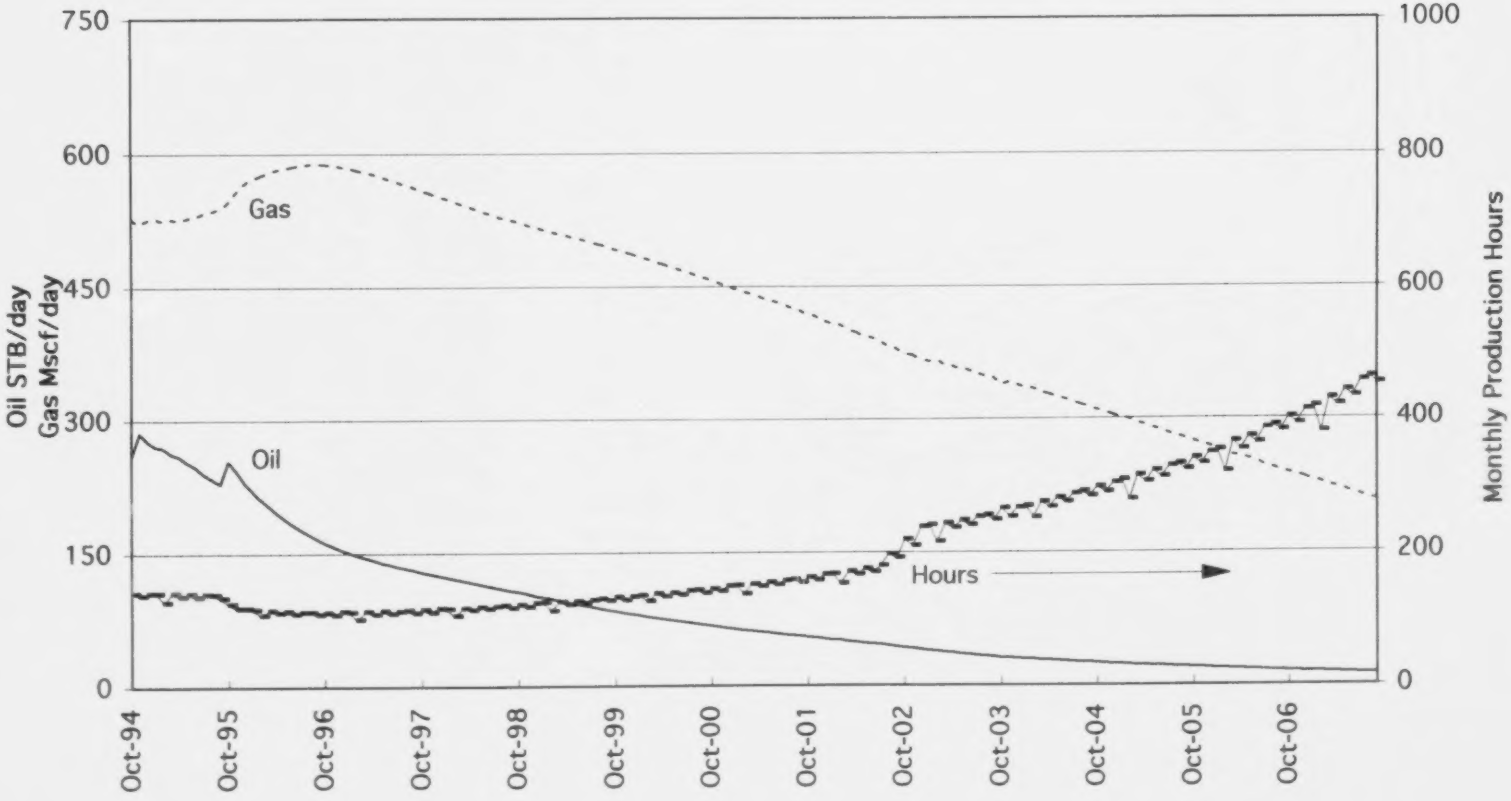


Figure 5.1(e): Primary Production Forecast (08-18-37-7W5)

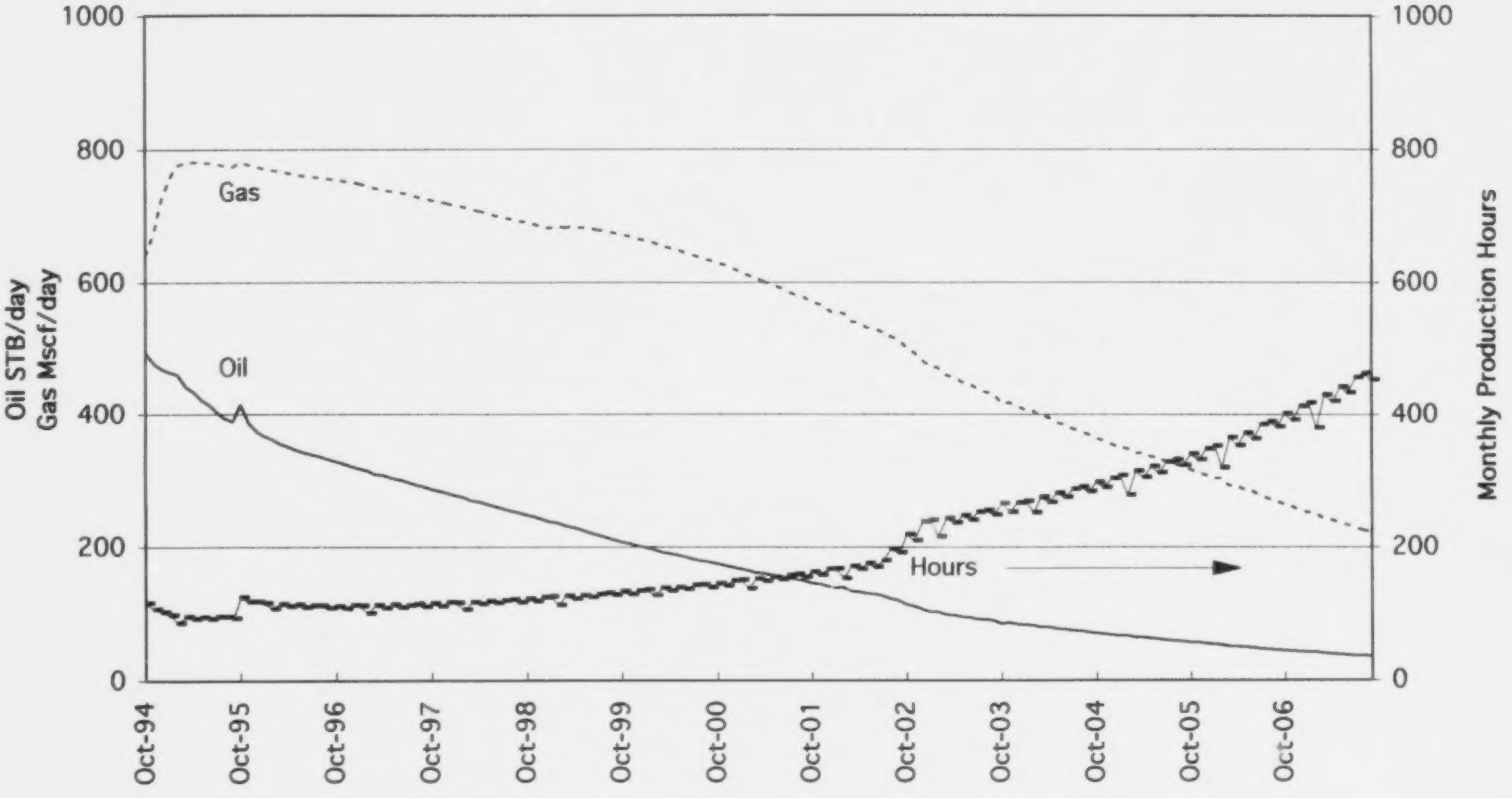


Figure 5.1(f): Primary Production Forecast (16-08-37-7W5)

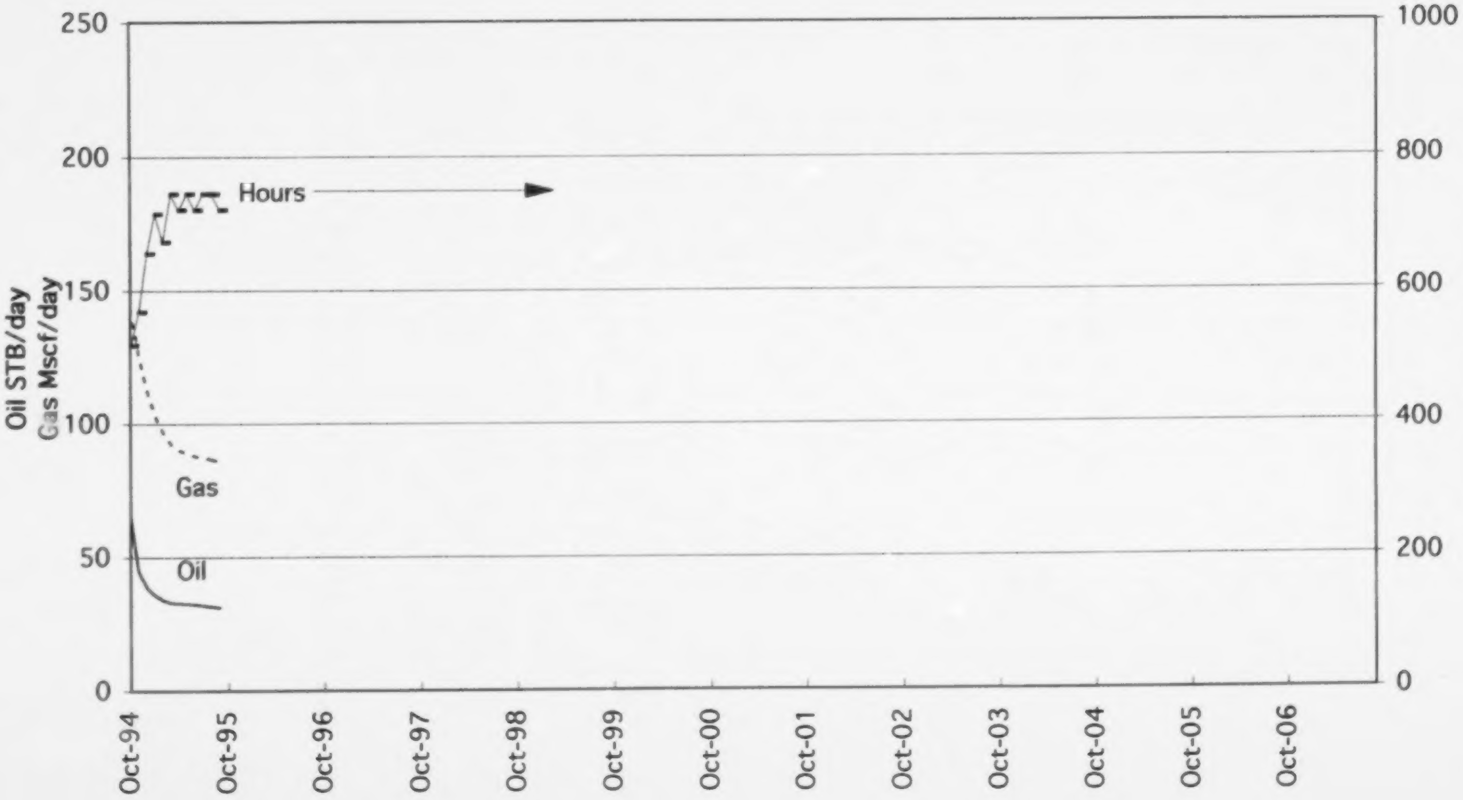


Figure 5.1(g): Primary Production Forecast (14-09-37-7W5)

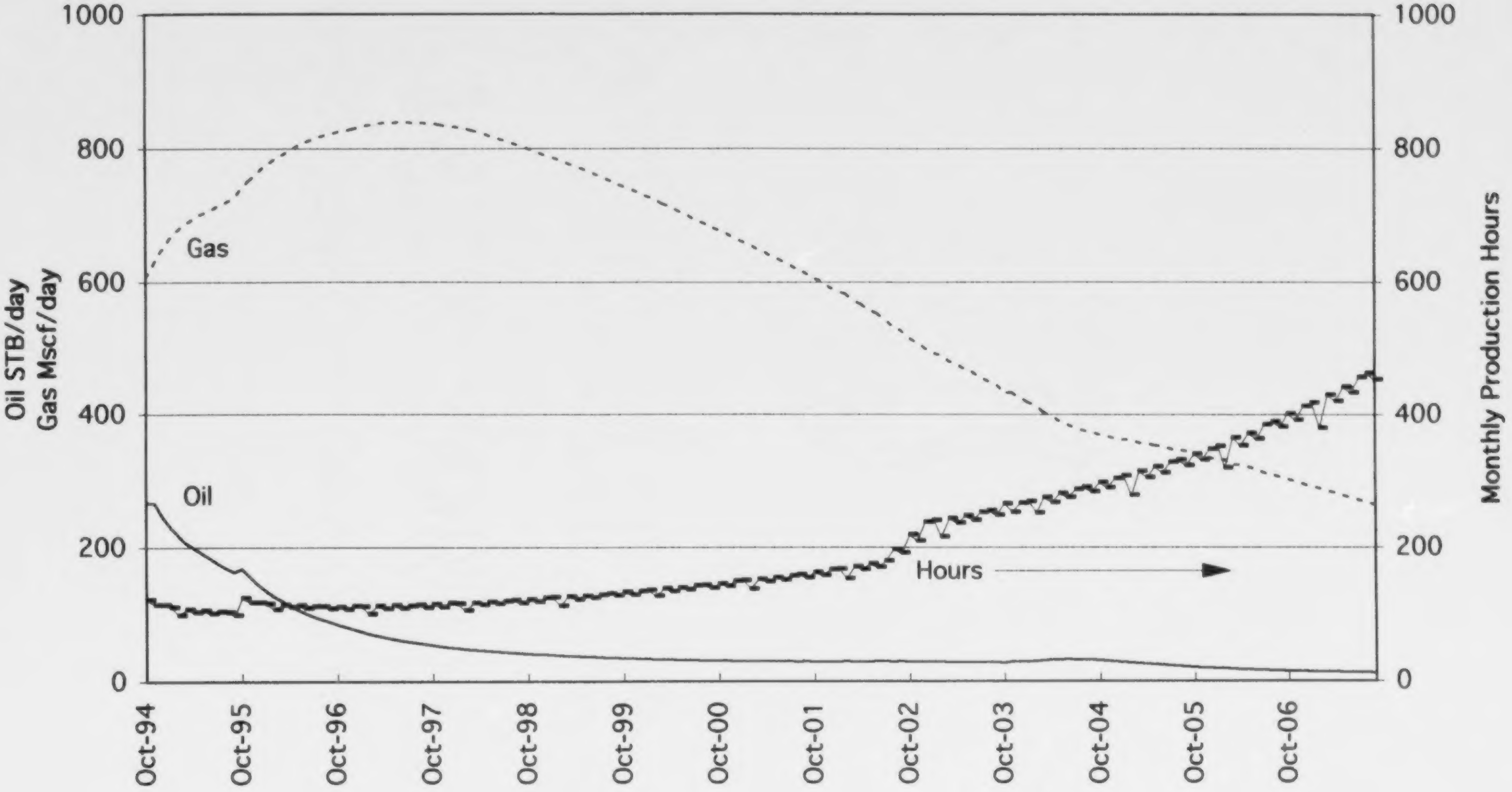


Figure 5.1(h): Primary Production Forecast (08-17-37-7W5)

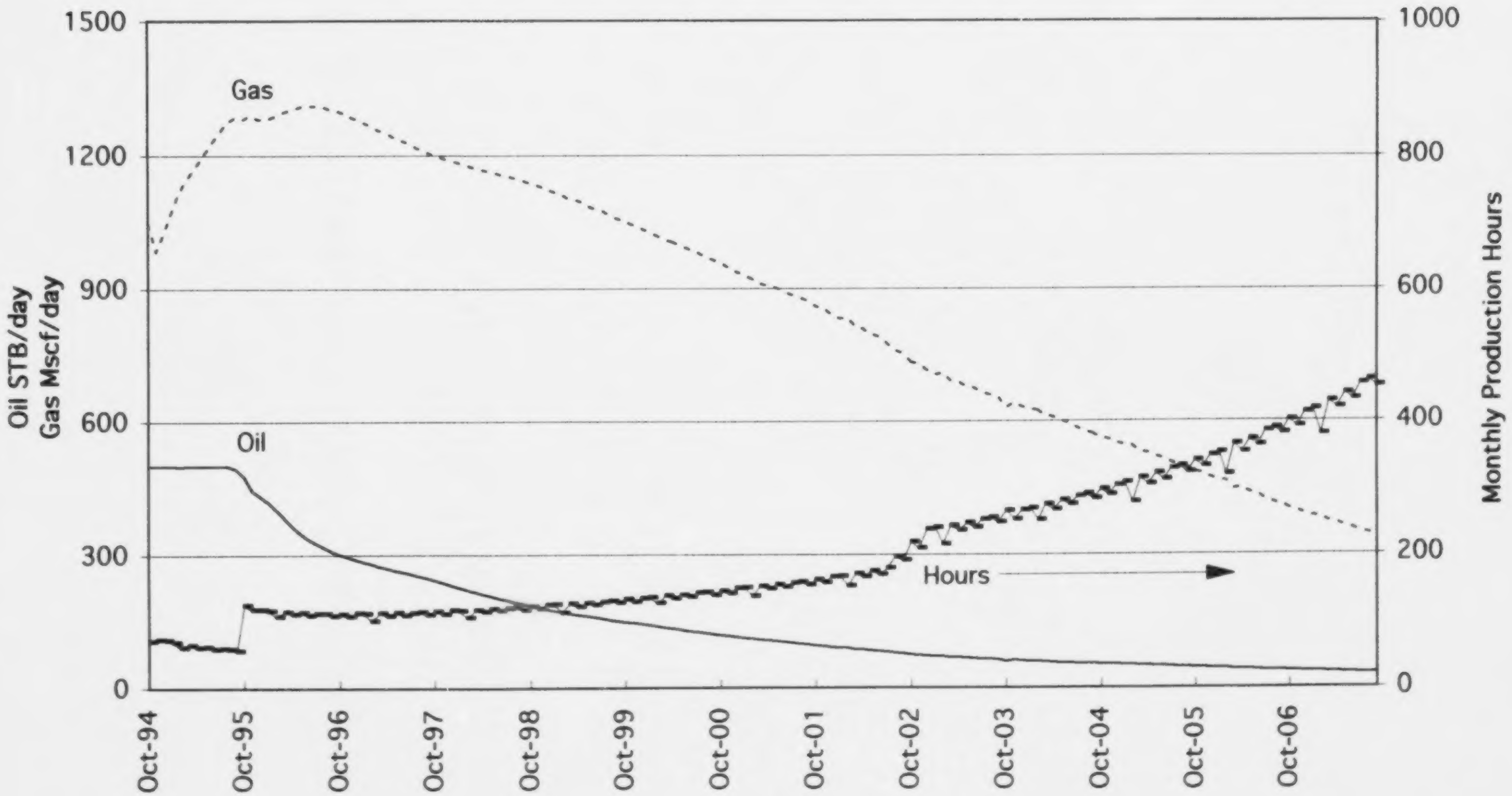


Figure 5.1(i): Primary Production Forecast (14-07-37-7W5)

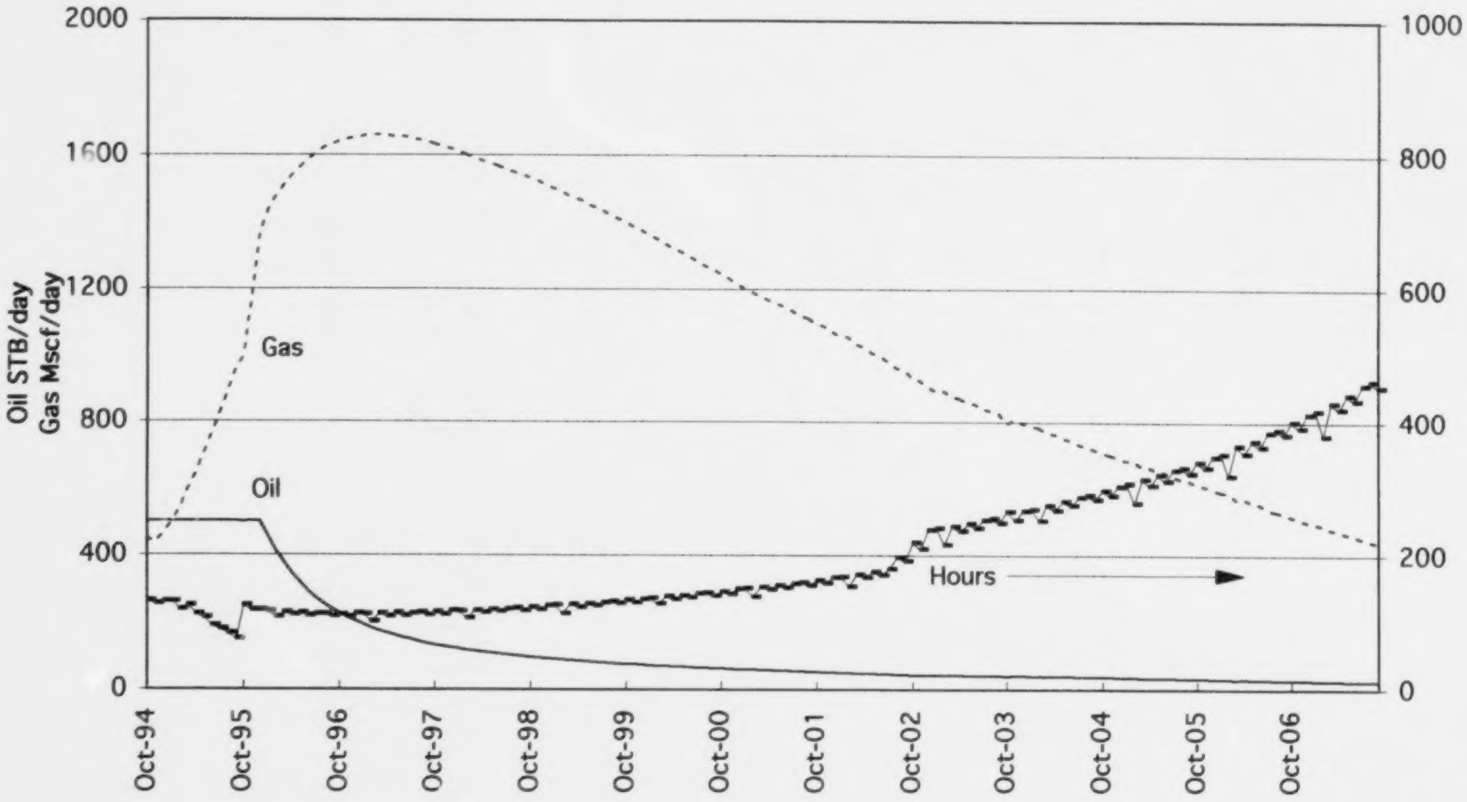


Figure 5.1(j): Primary Production Forecast (14-12-37-8W5)

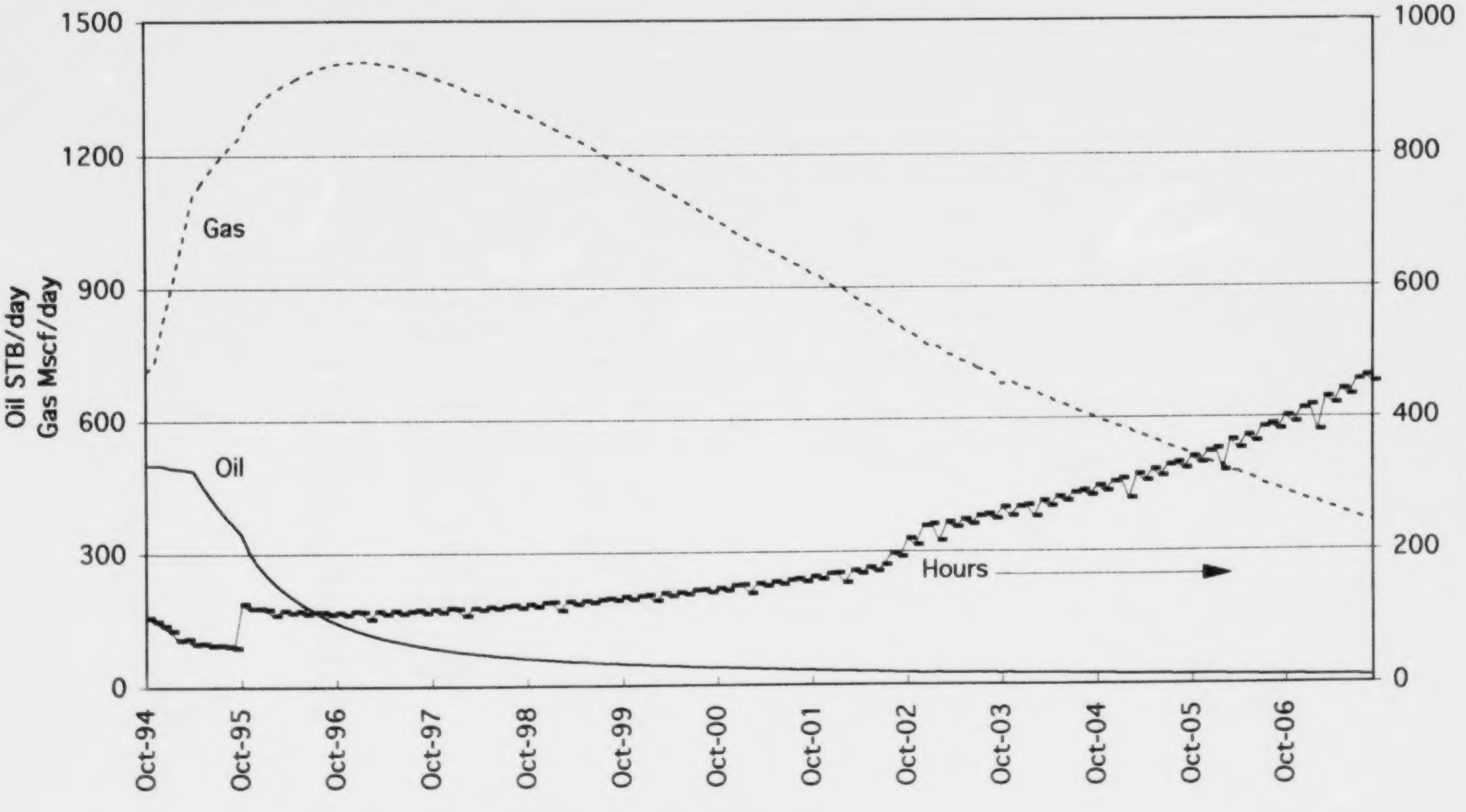


Figure 5.1(k): Primary Production Forecast (16-12-37-8W5)

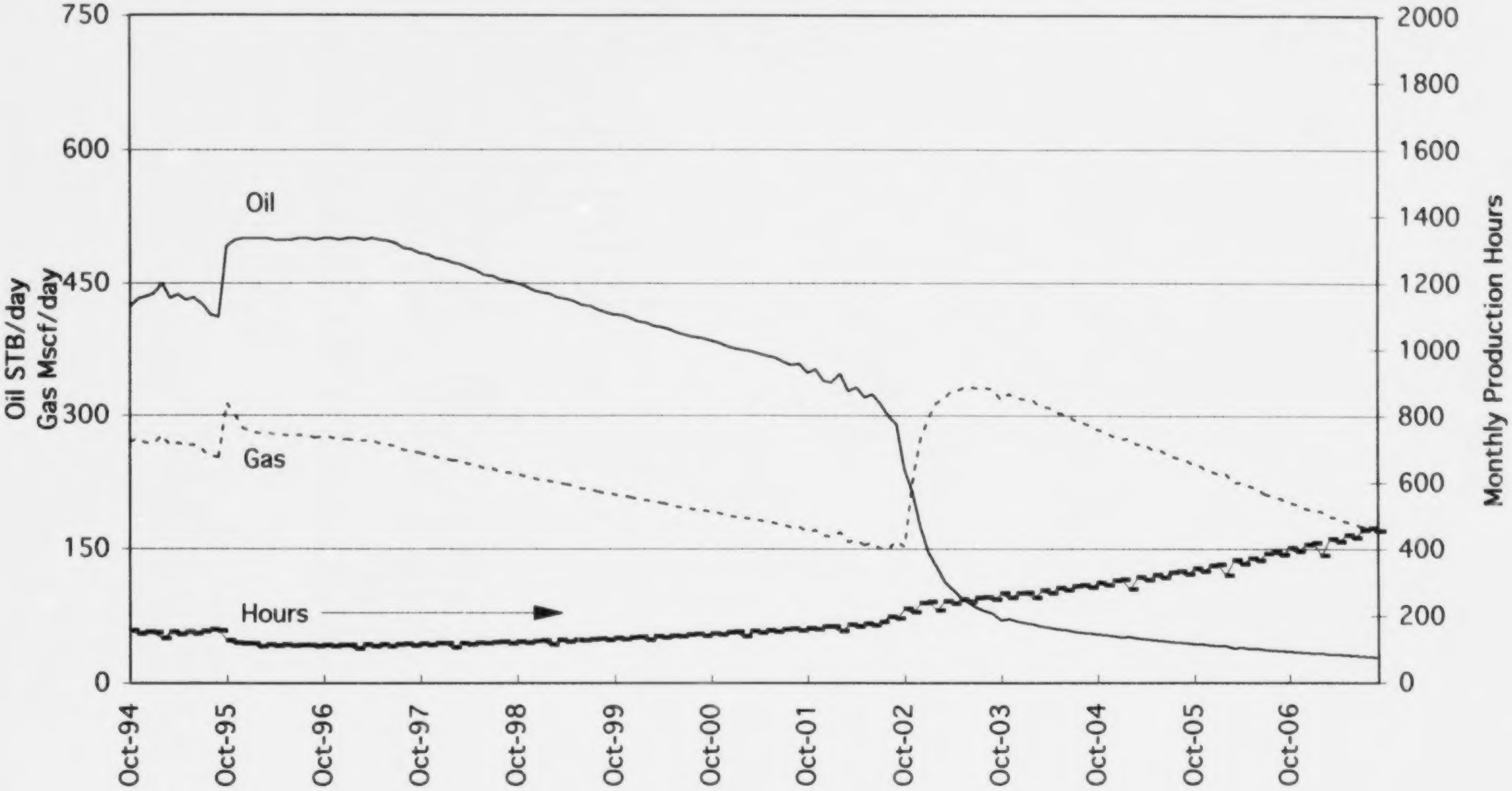


Figure 5.1(I): Primary Production Forecast (08-07-37-7W5)

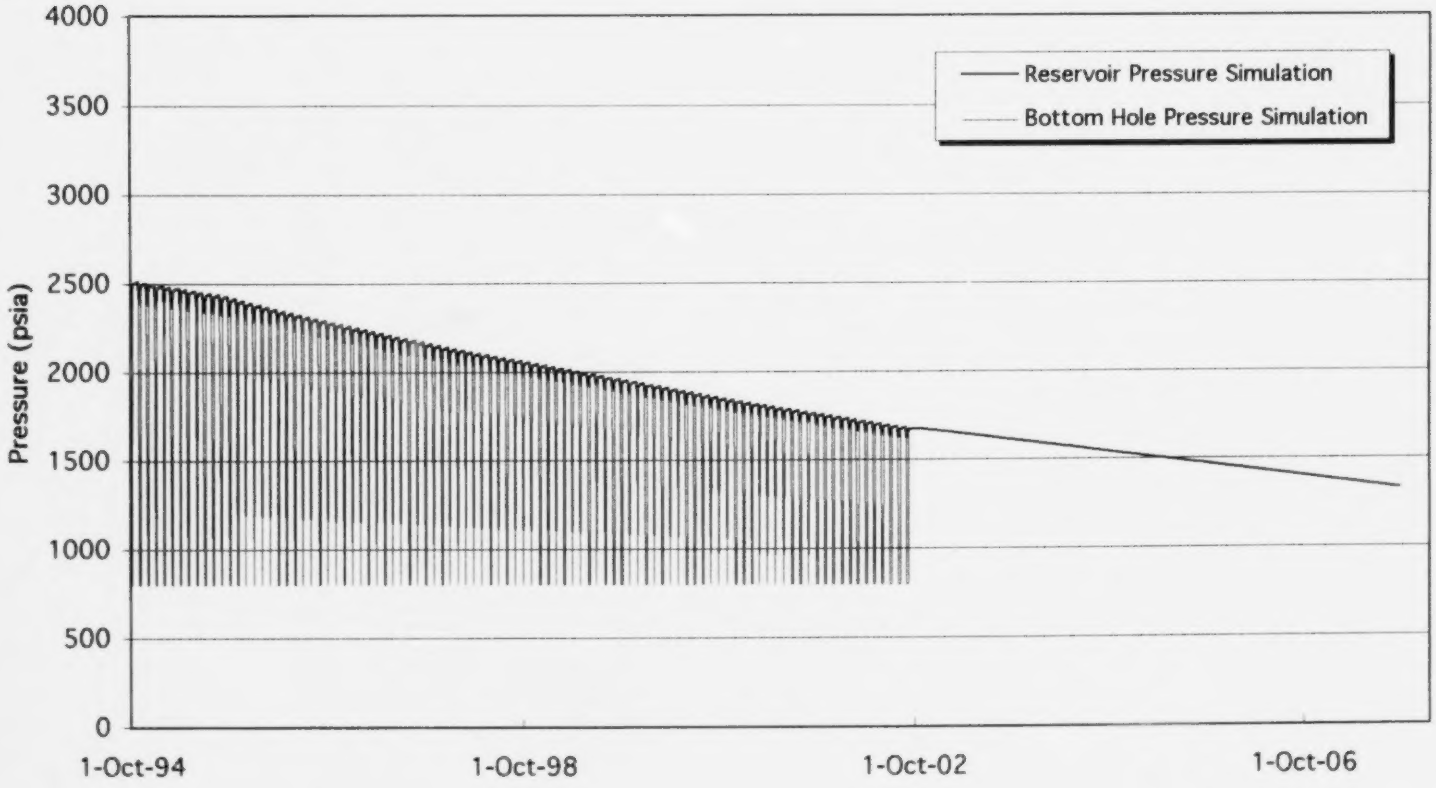


Figure 5.2(a): Primary Pressure Prediction (08-13-37-8W5)

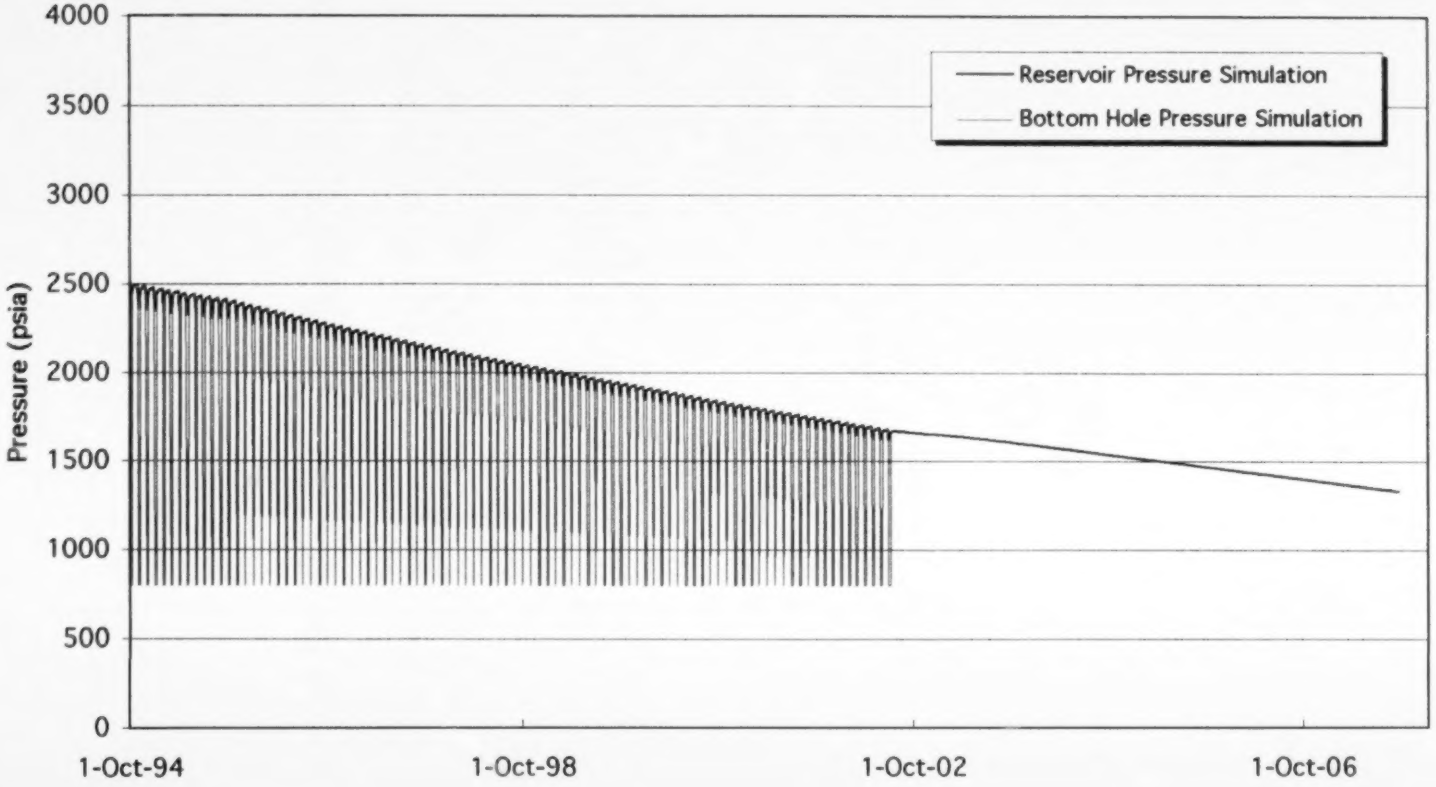


Figure 5.2(b): Primary Pressure Prediction (06-13-37-8W5)

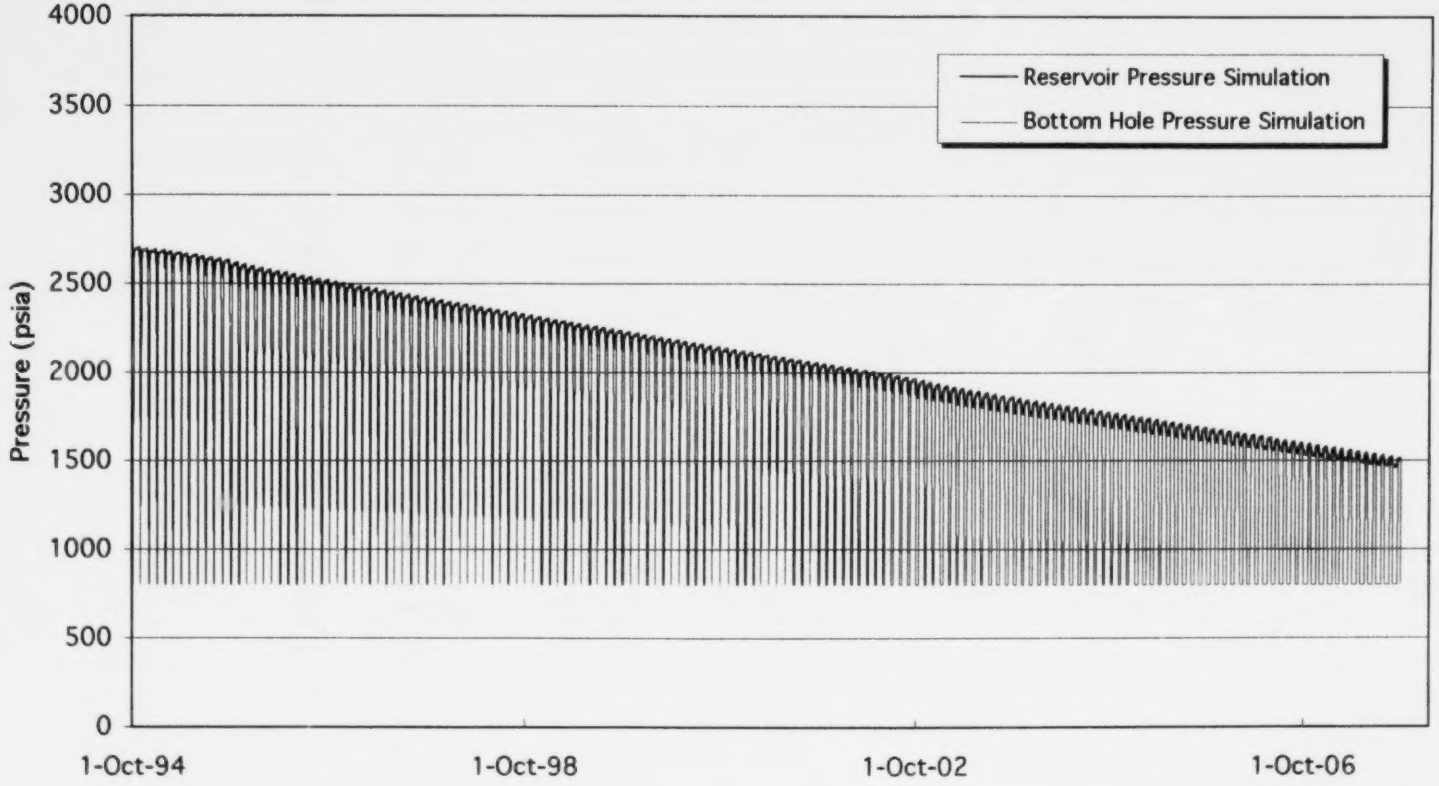


Figure 5.2(c): Primary Pressure Prediction (06-16-37-7W5)

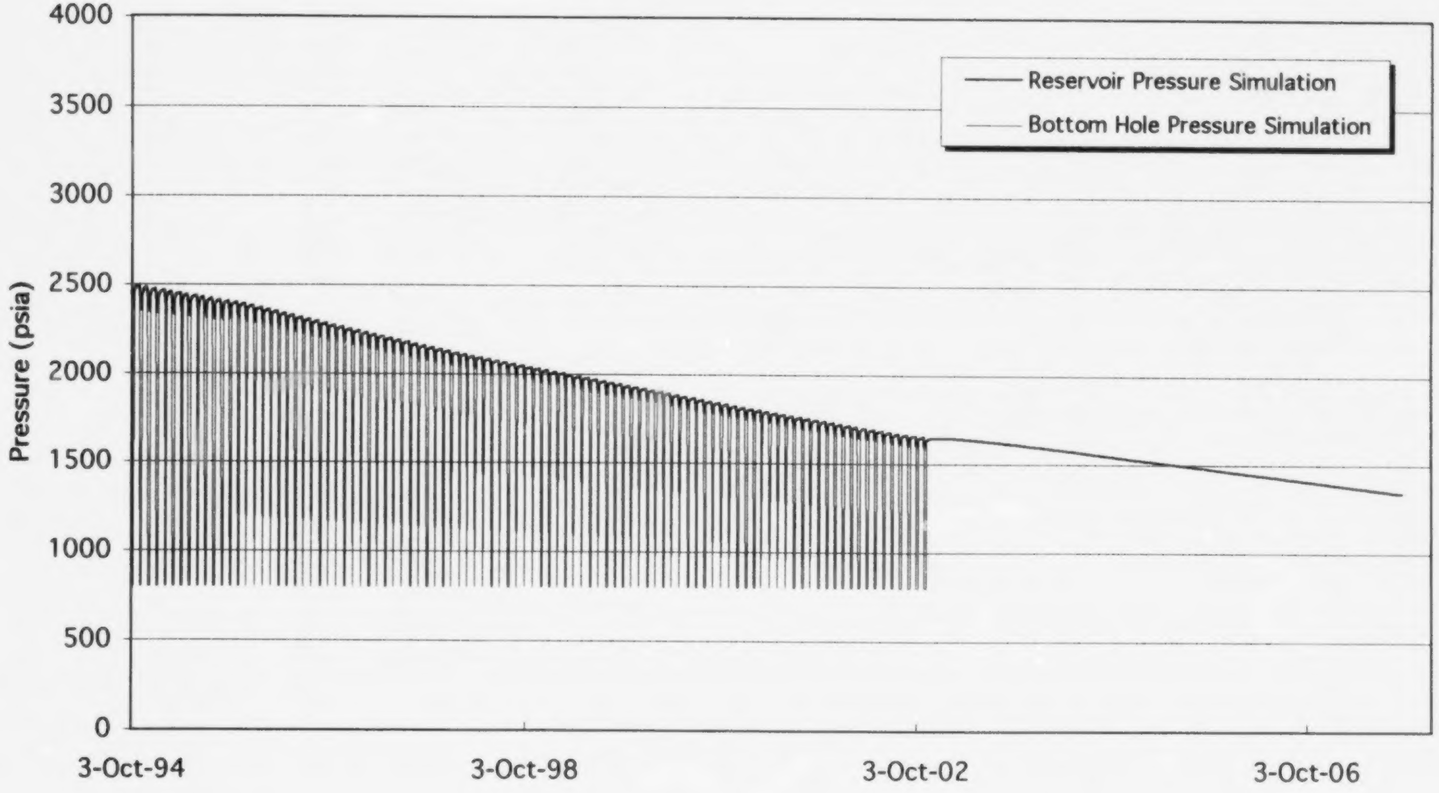


Figure 5.2(d): Primary Pressure Prediction (08-14-37-8W5)

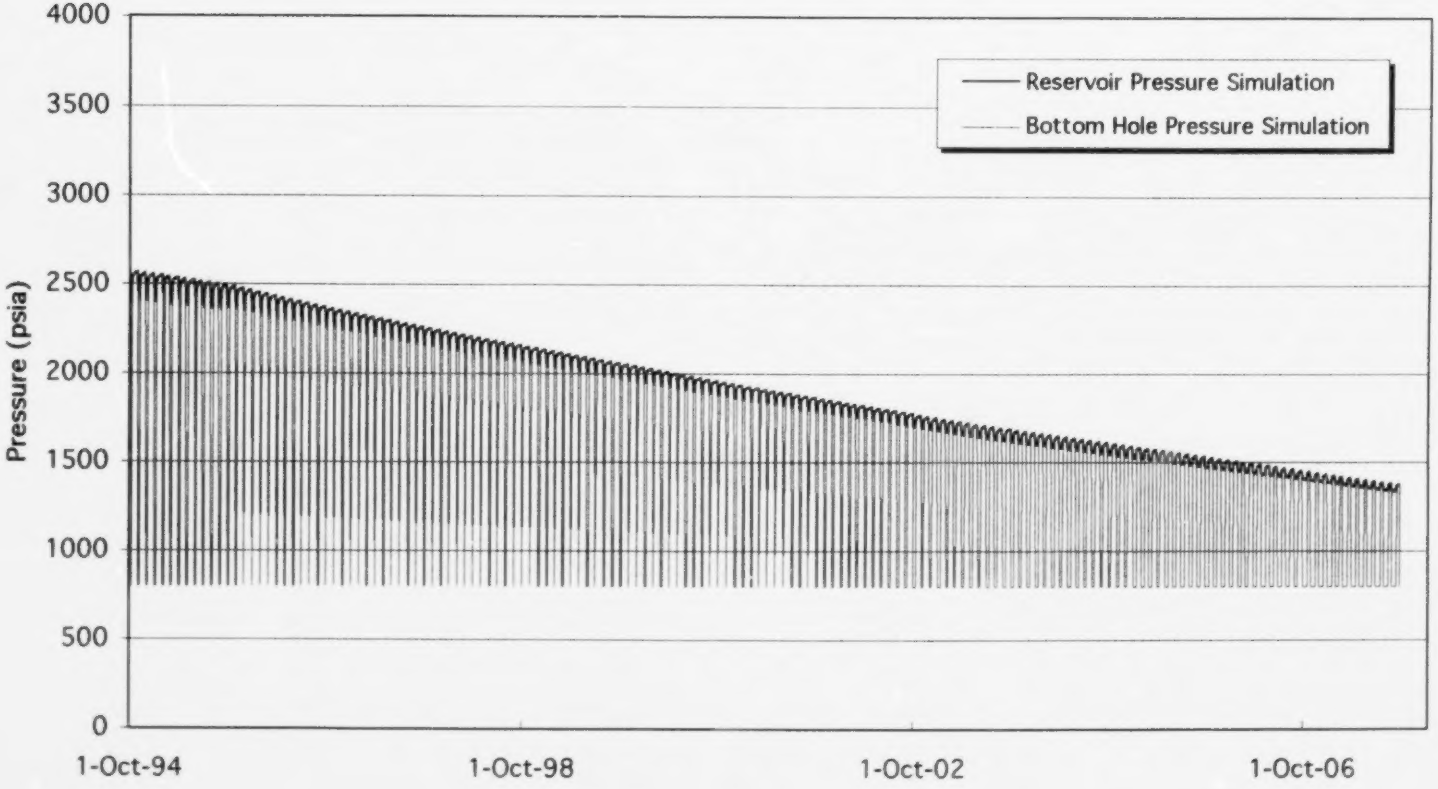


Figure 5.2(e): Primary Pressure Prediction (08-18-37-7W5)

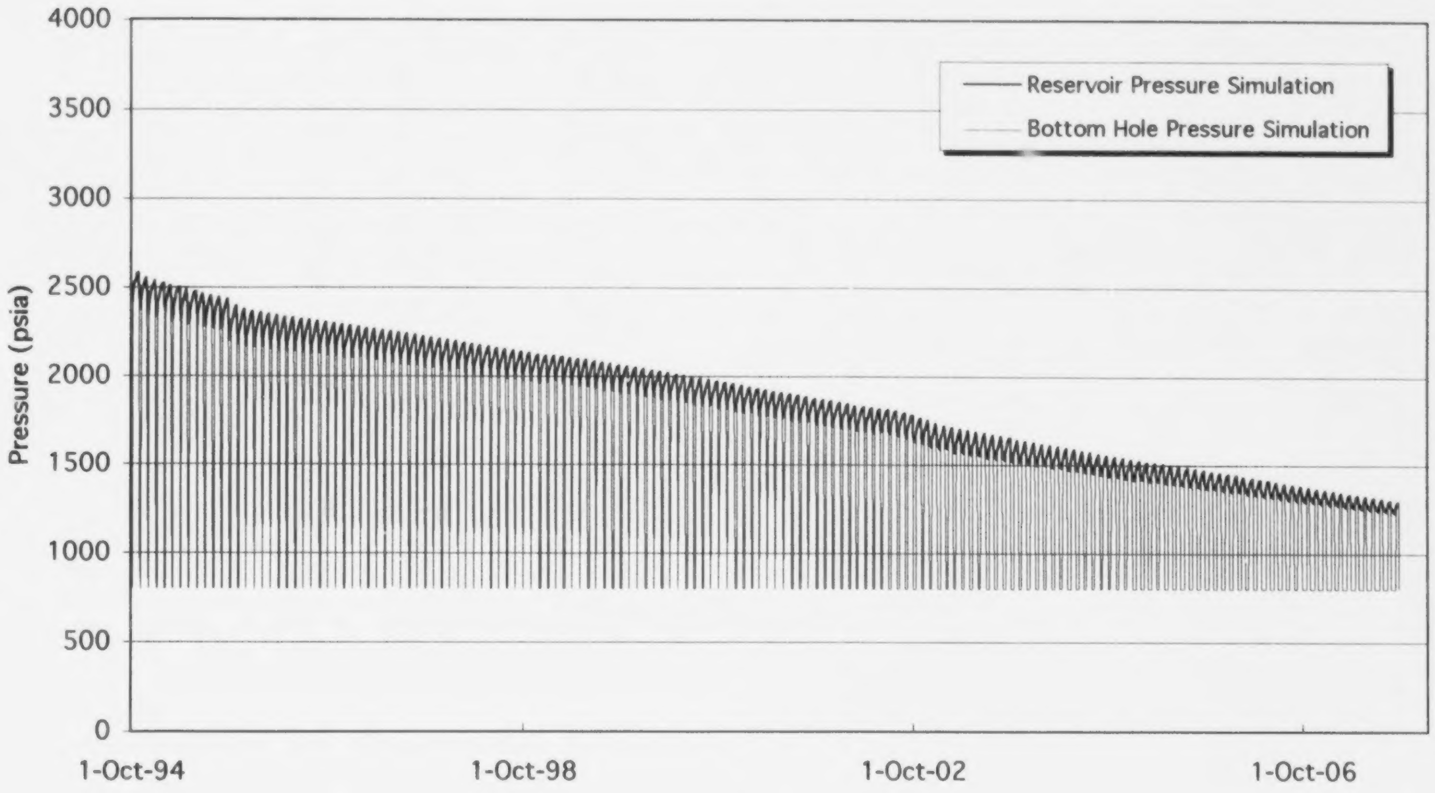


Figure 5.2(f): Primary Pressure Prediction (16-08-37-7W5)

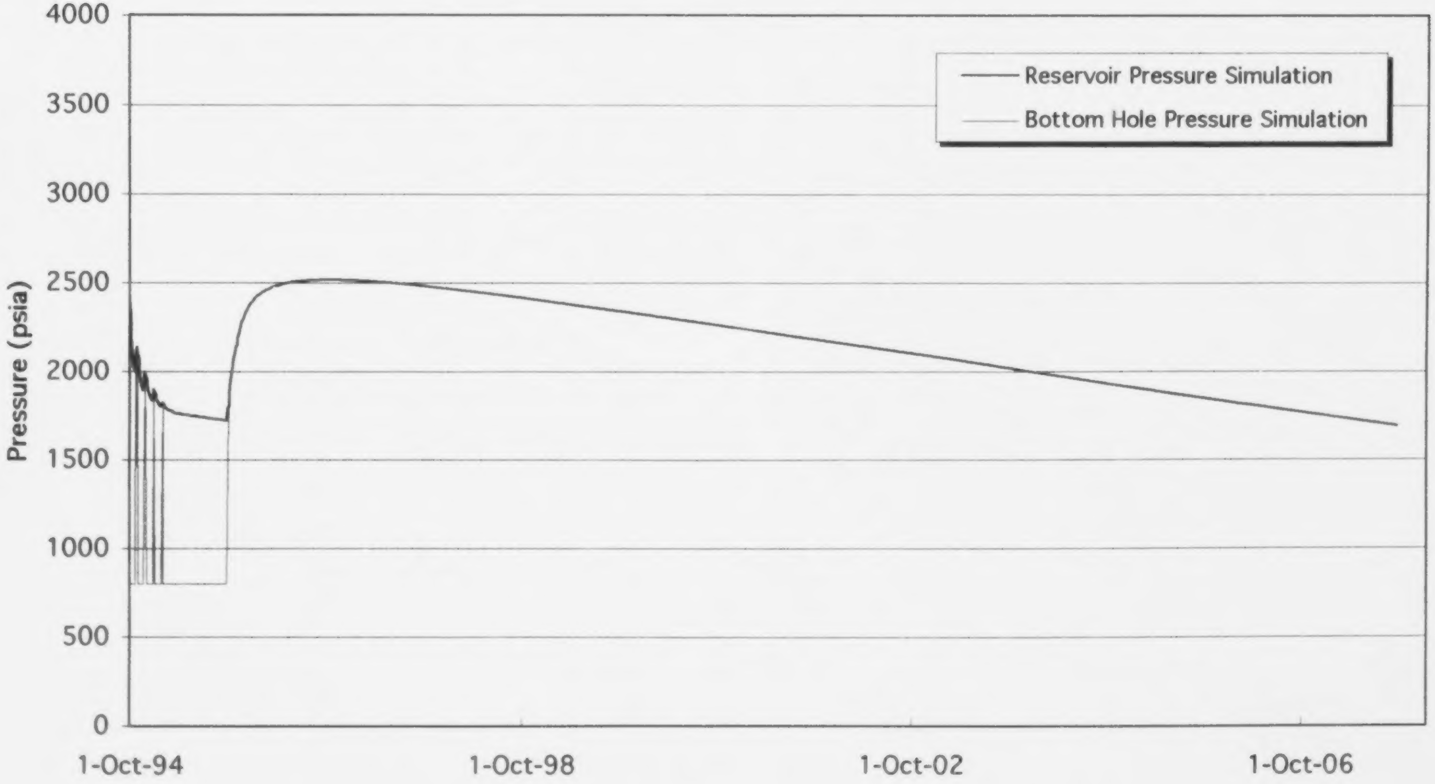


Figure 5.2(g): Primary Pressure Prediction (14-09-37-7W5)

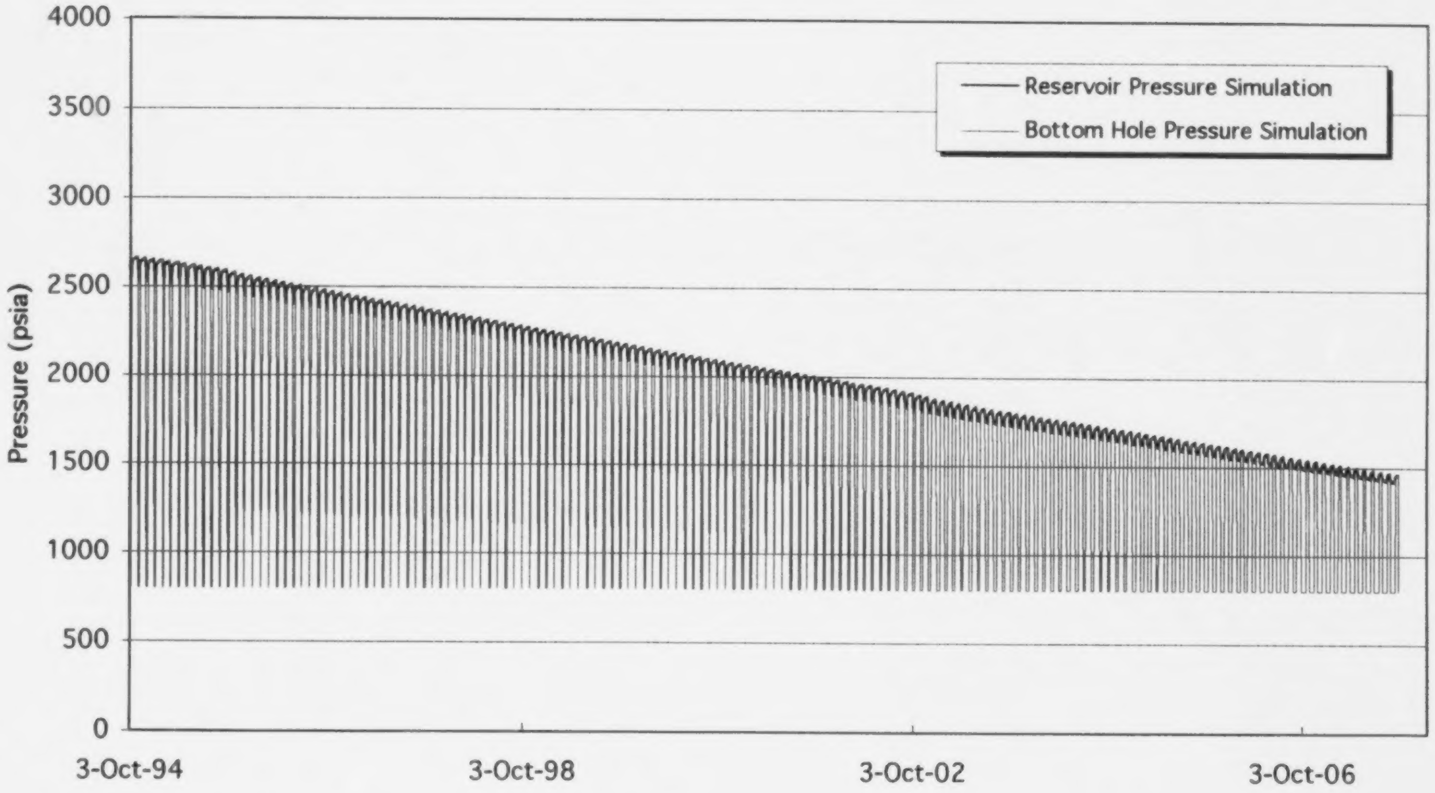


Figure 5.2(h): Primary Pressure Prediction (08-17-37-7W5)

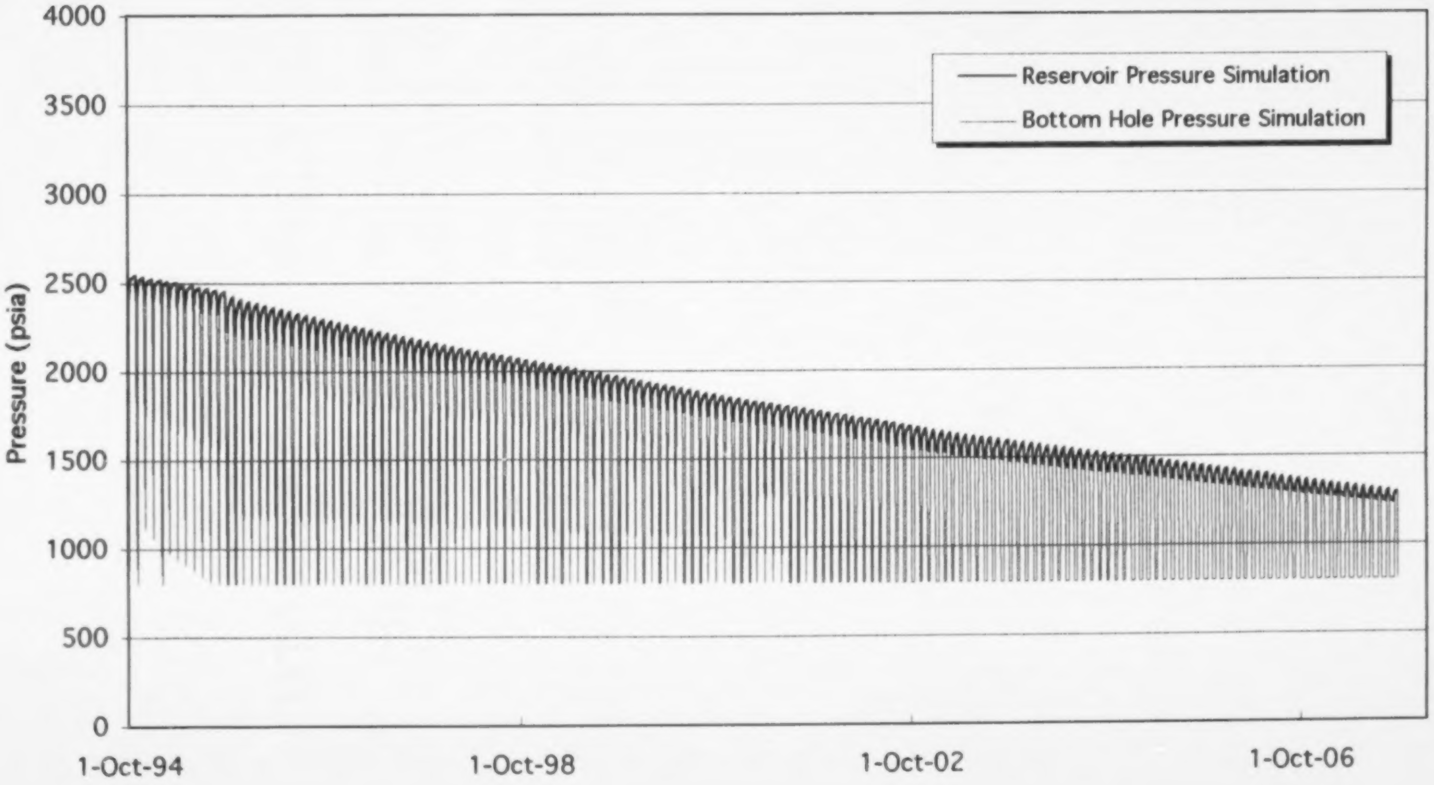


Figure 5.2(i): Primary Pressure Prediction (14-07-37-7W5)

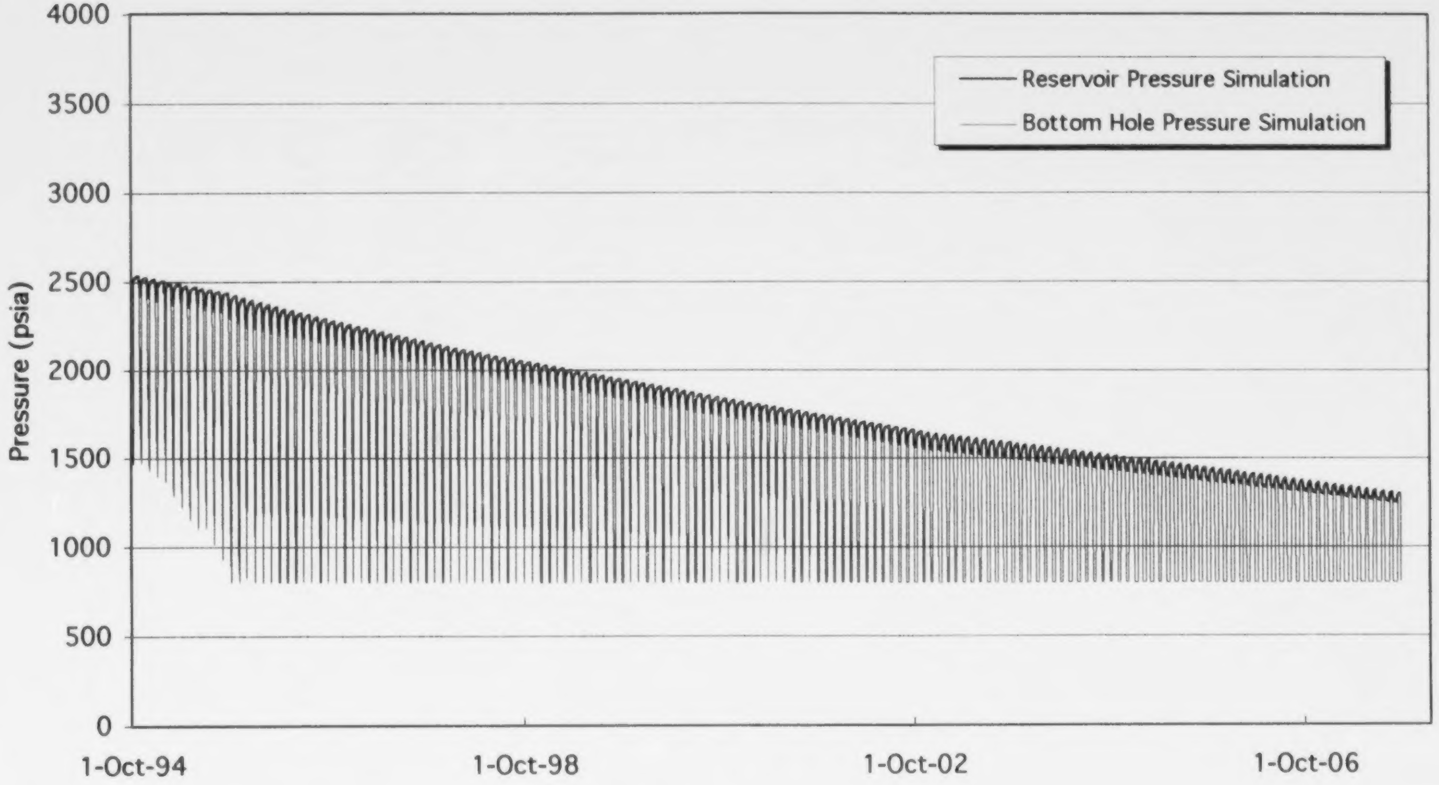


Figure 5.2(j): Primary Pressure Prediction (14-12-37-8W5)

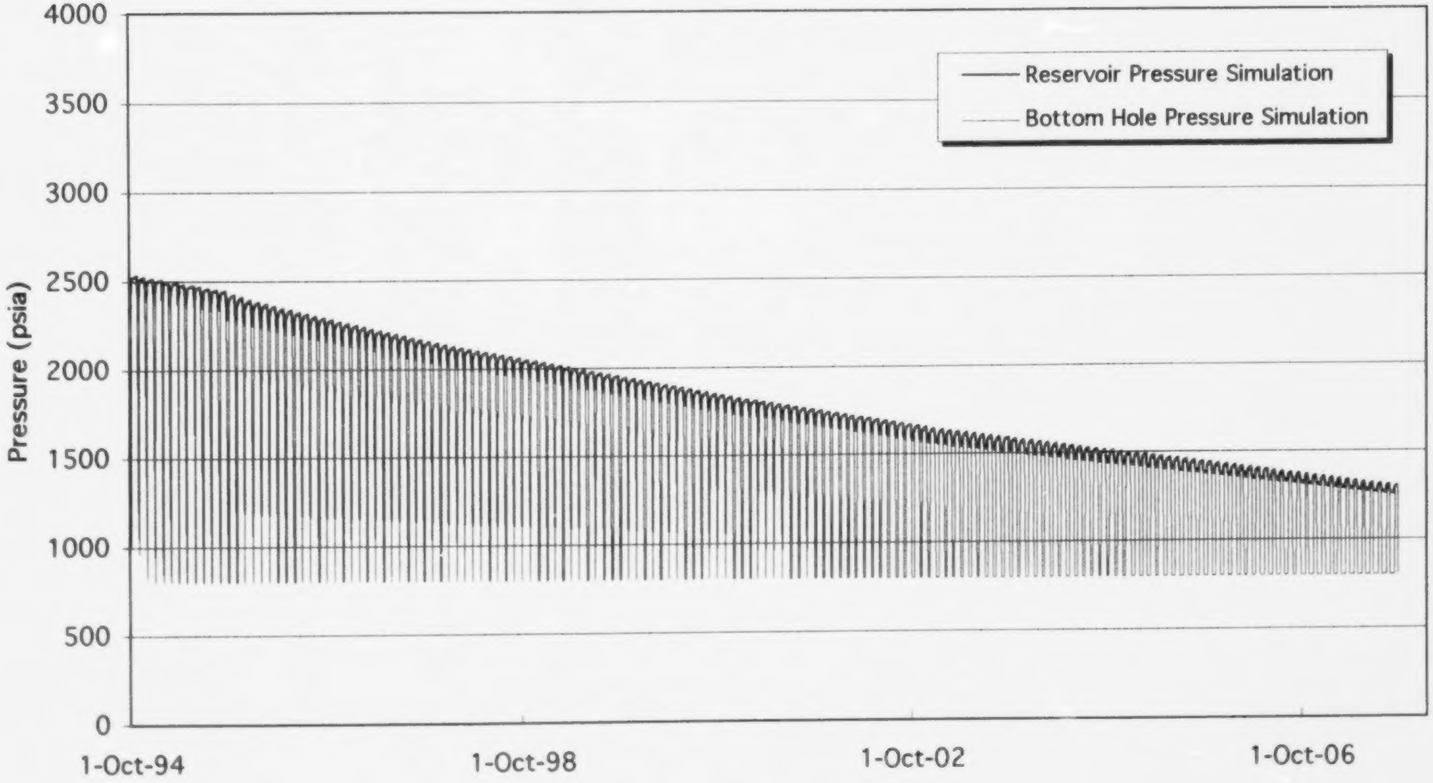


Figure 5.2(k): Primary Pressure Prediction (16-12-37-8W5)

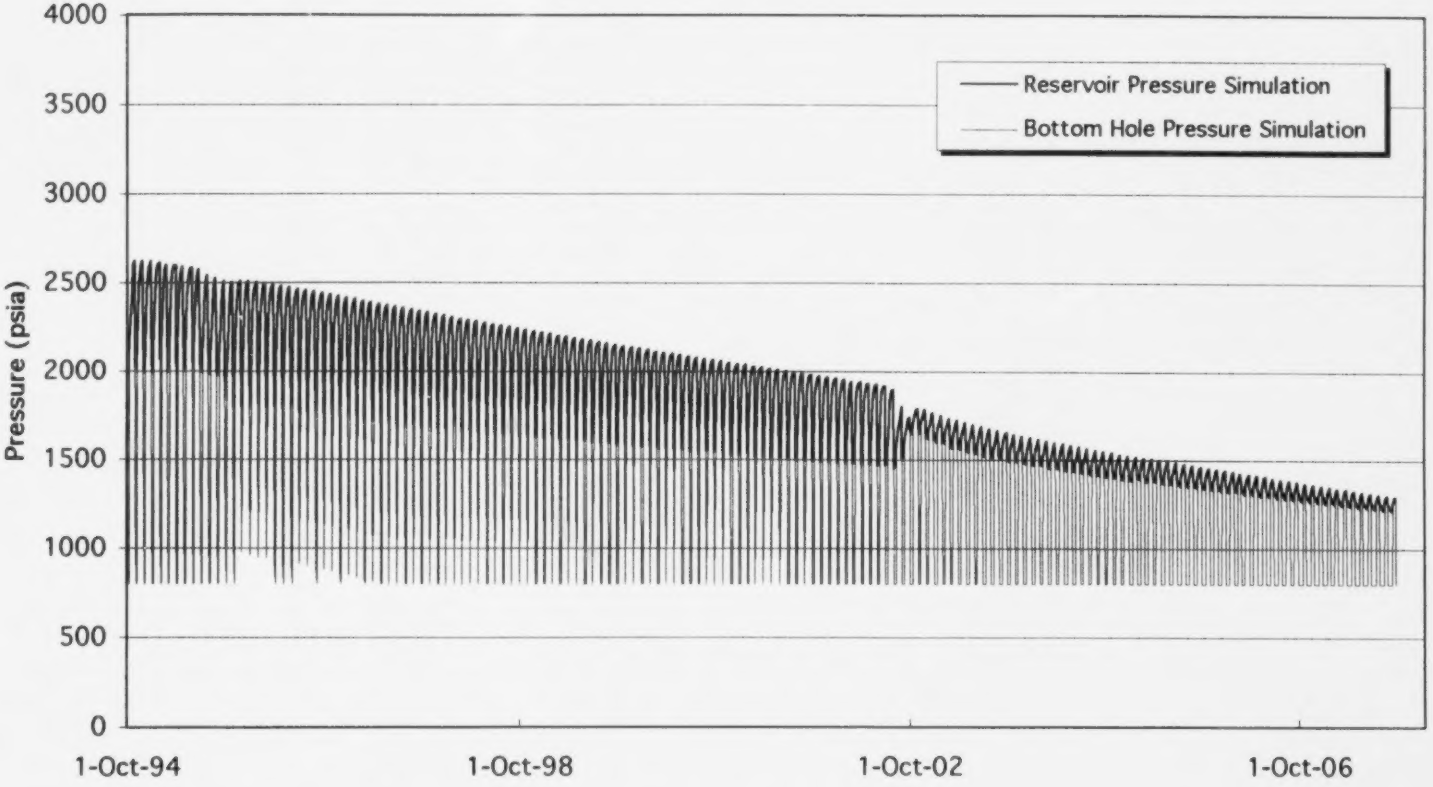


Figure 5.2(l): Primary Pressure Prediction (08-07-37-7W5)

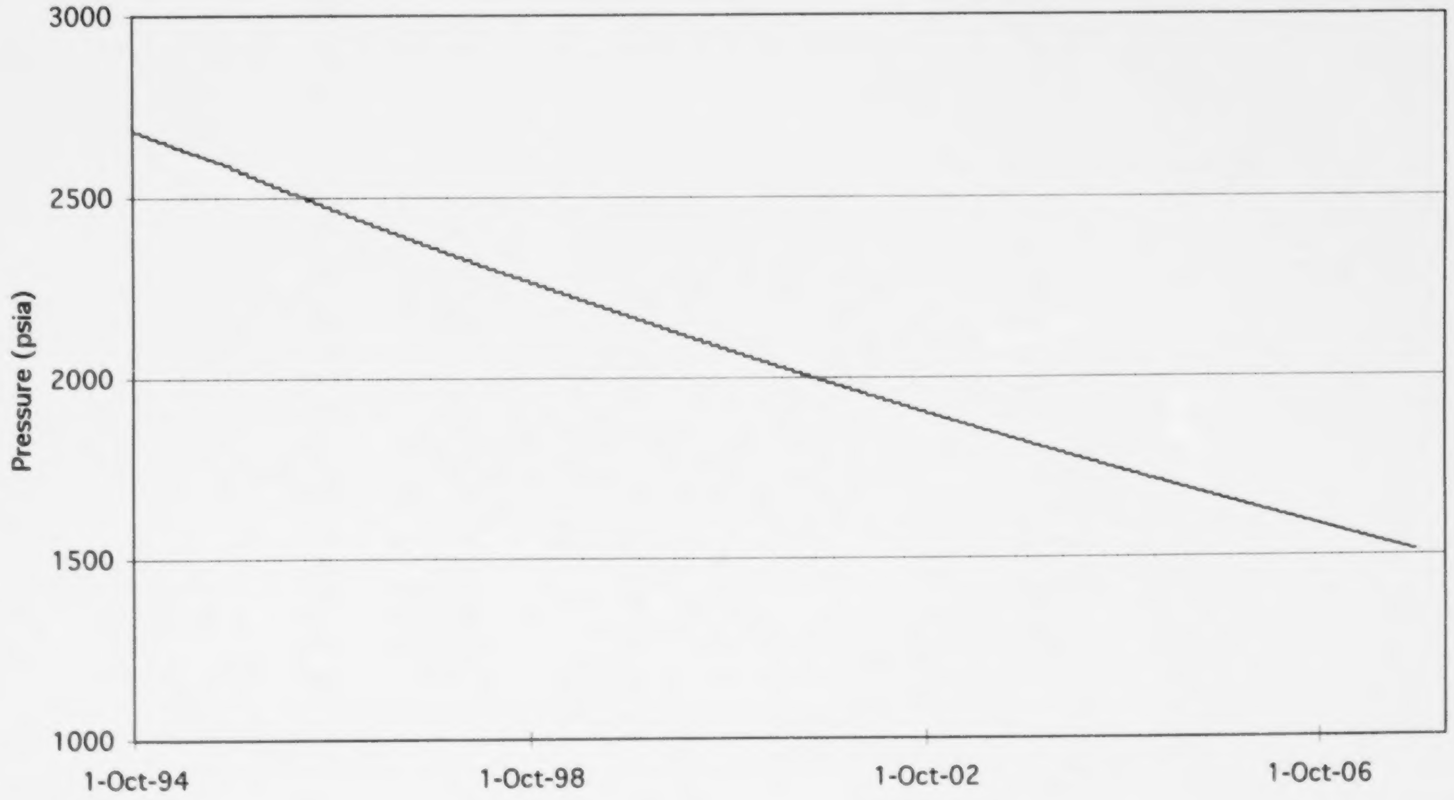


Figure 5.3(a): Primary Average Reservoir Pressure Prediction

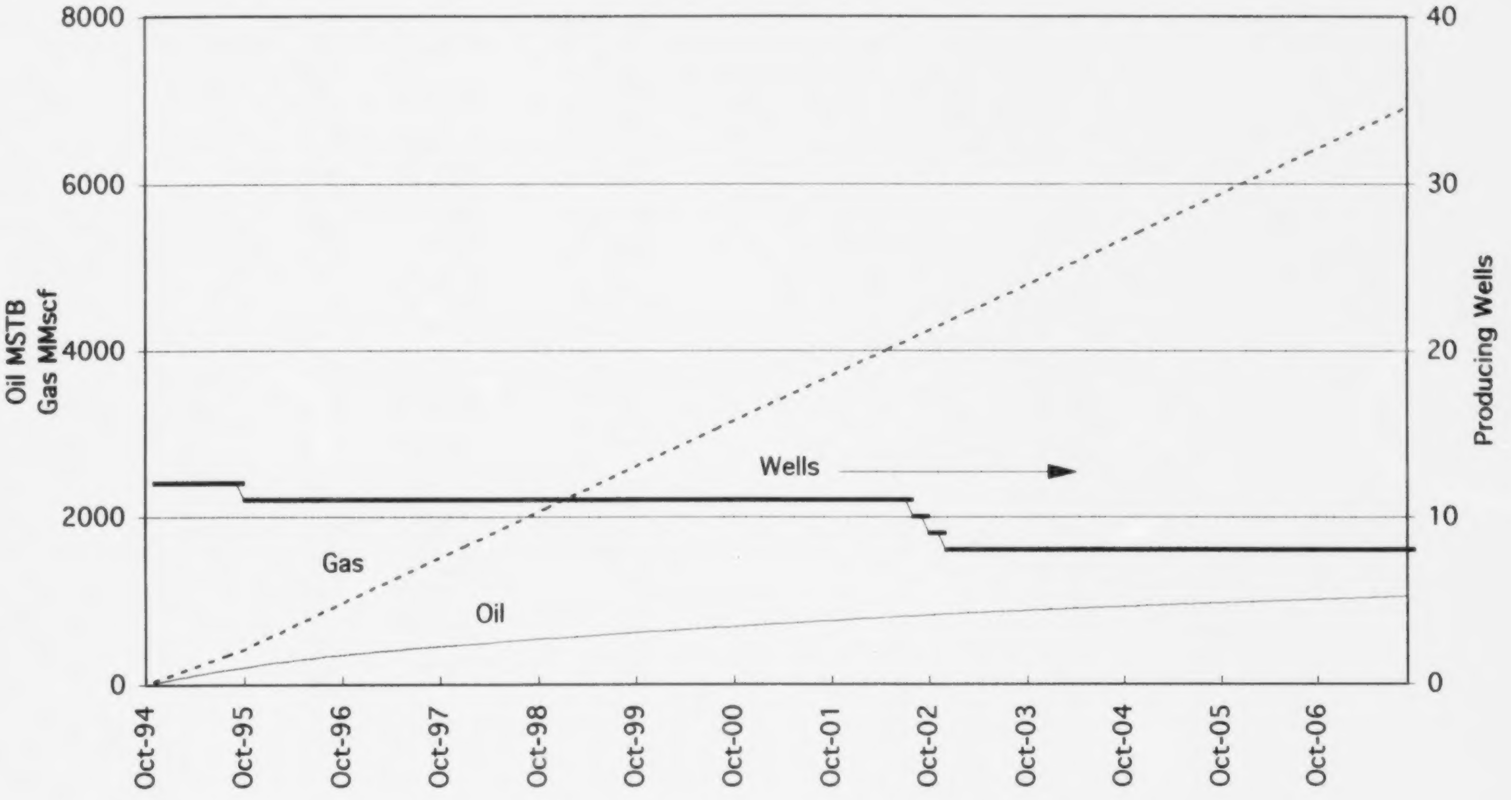


Figure 5.3(b): Pool Cumulative Primary Production Prediction

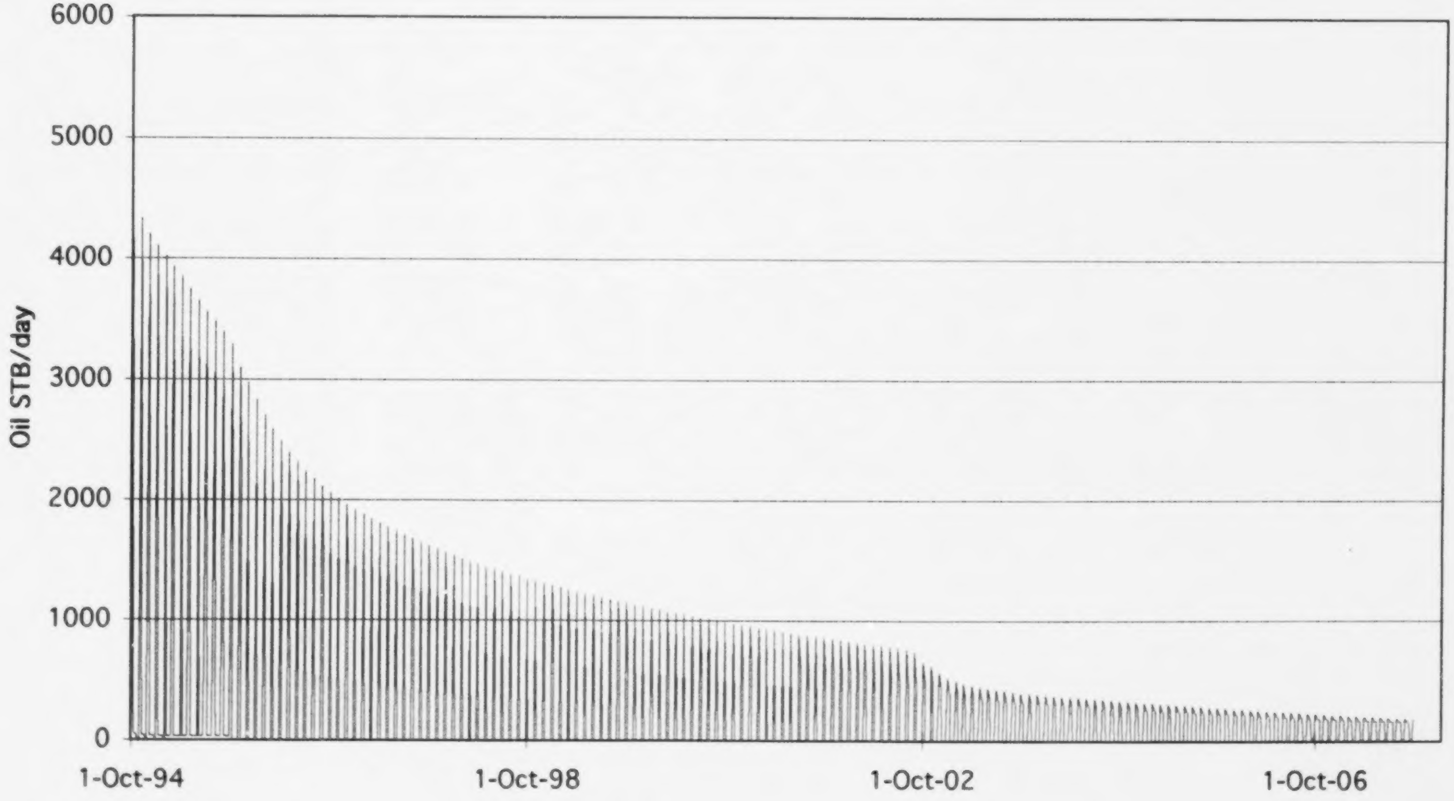


Figure 5.4(a): Pool Primary Oil Production Rate Forecast

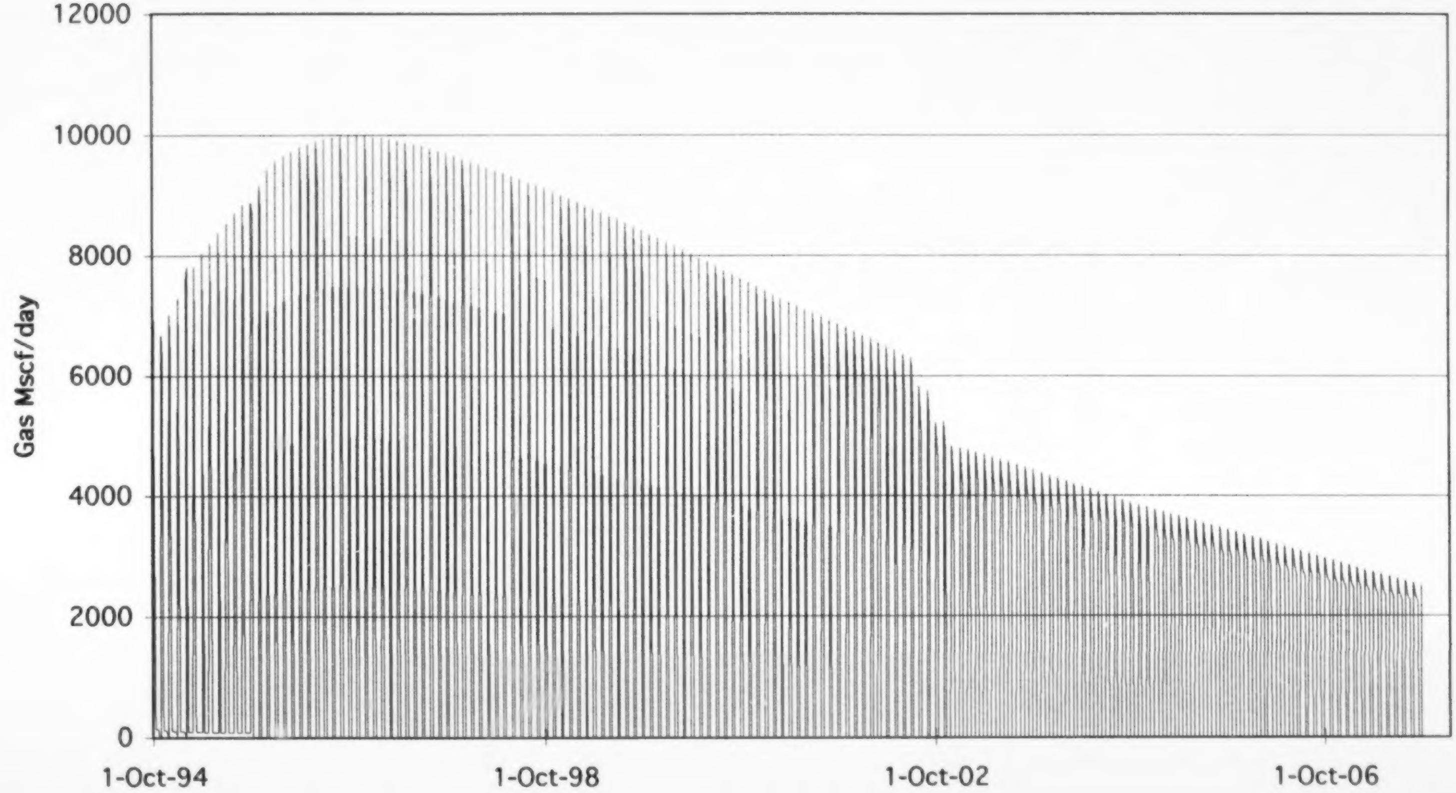


Figure 5.4(b): Pool Primary Gas Production Rate Forecast

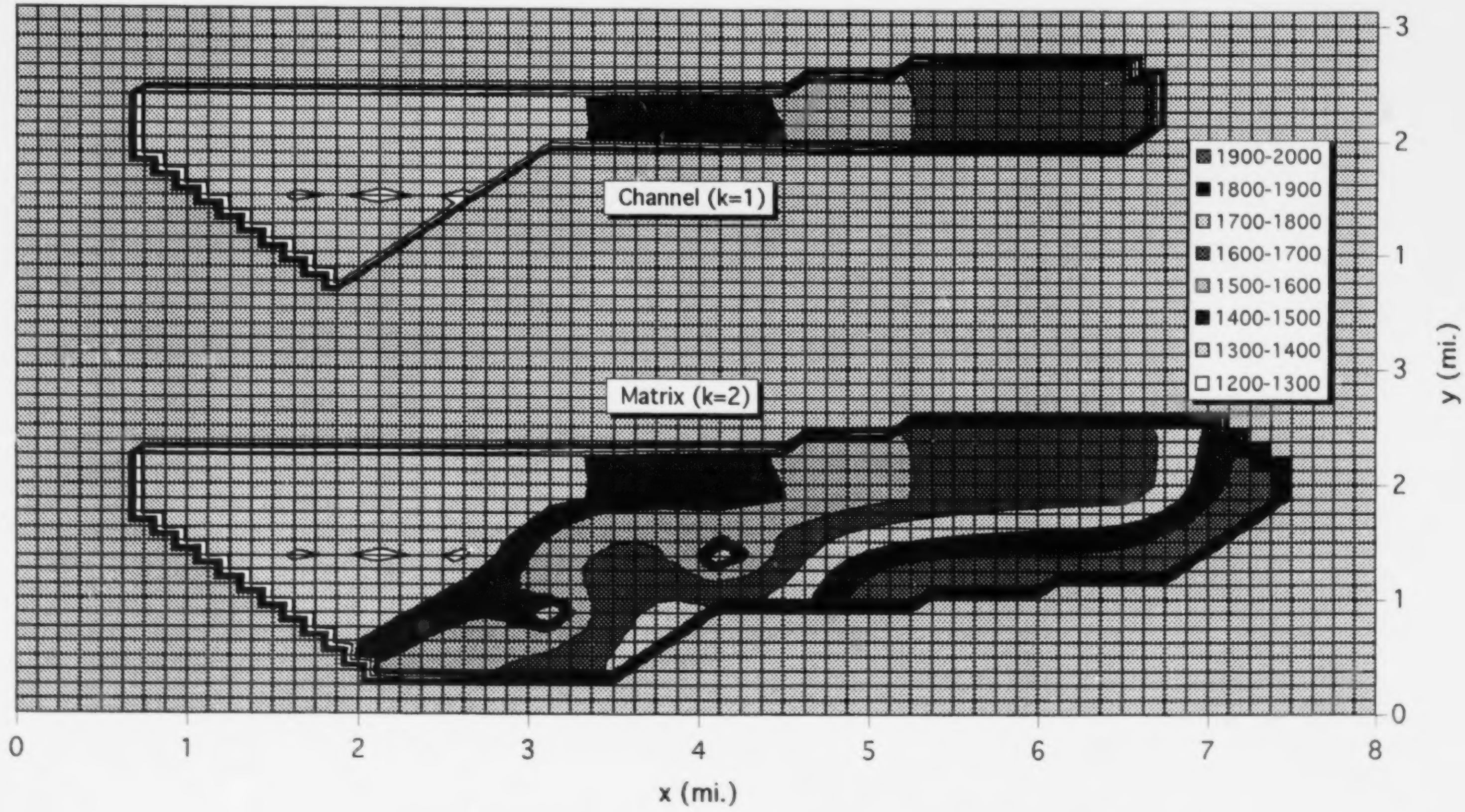


Figure 5.5(a): Primary (Oct-07) Pressure p (psia)

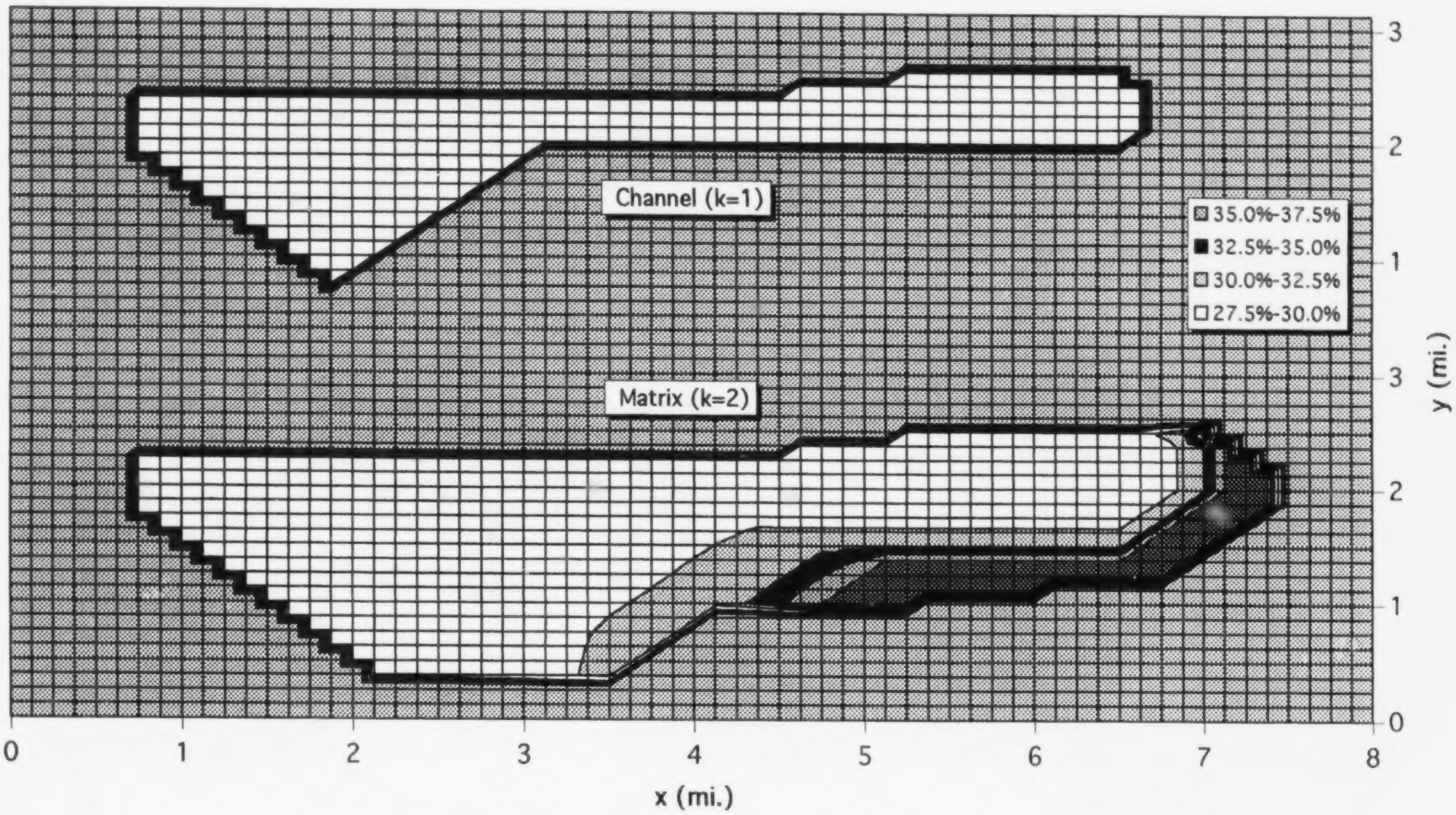


Figure 5.5(b): Primary (Oct-07) Water Saturation S_w

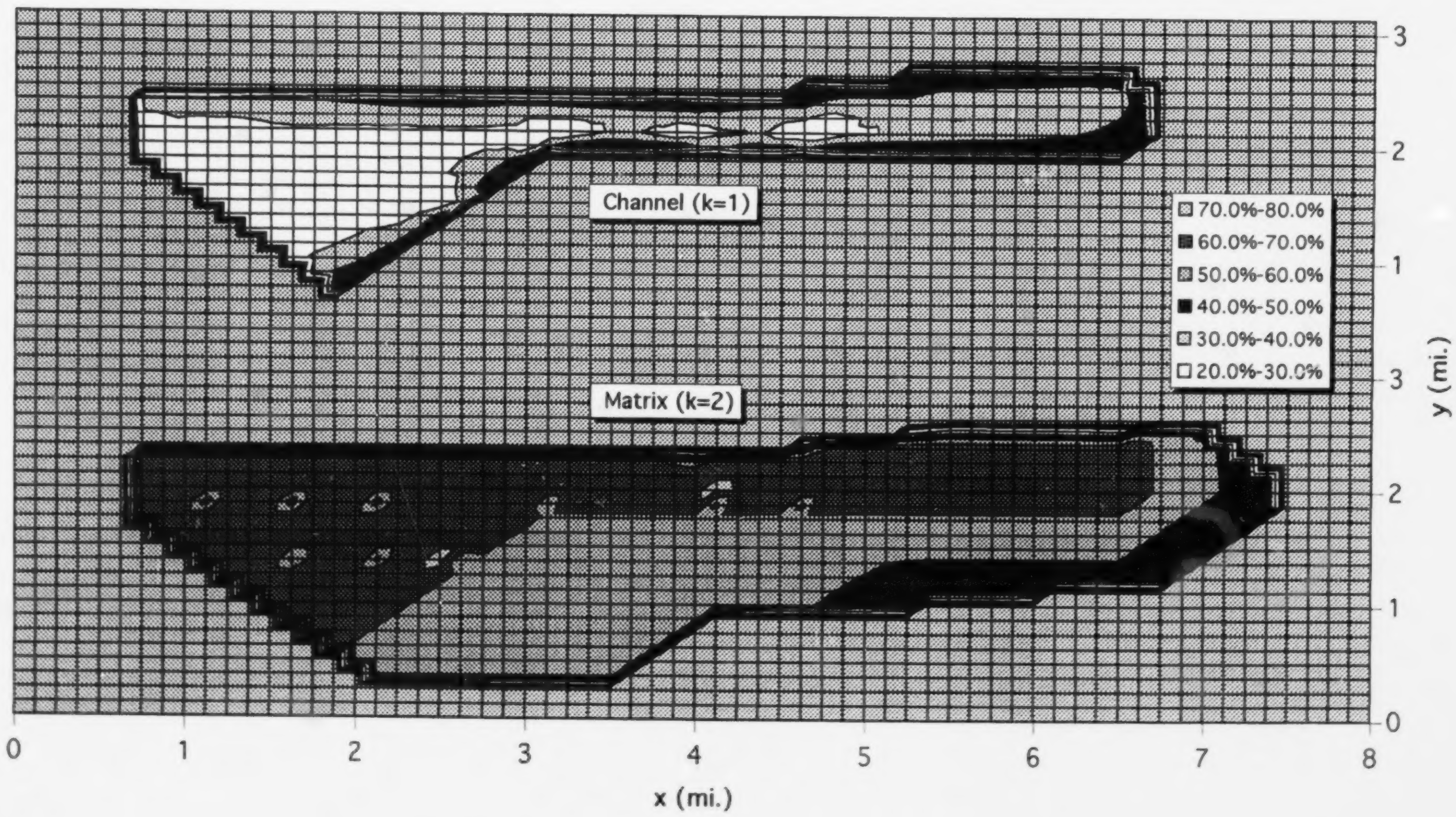


Figure 5.5(c): Primary (Oct-07) Oil Saturation S_o

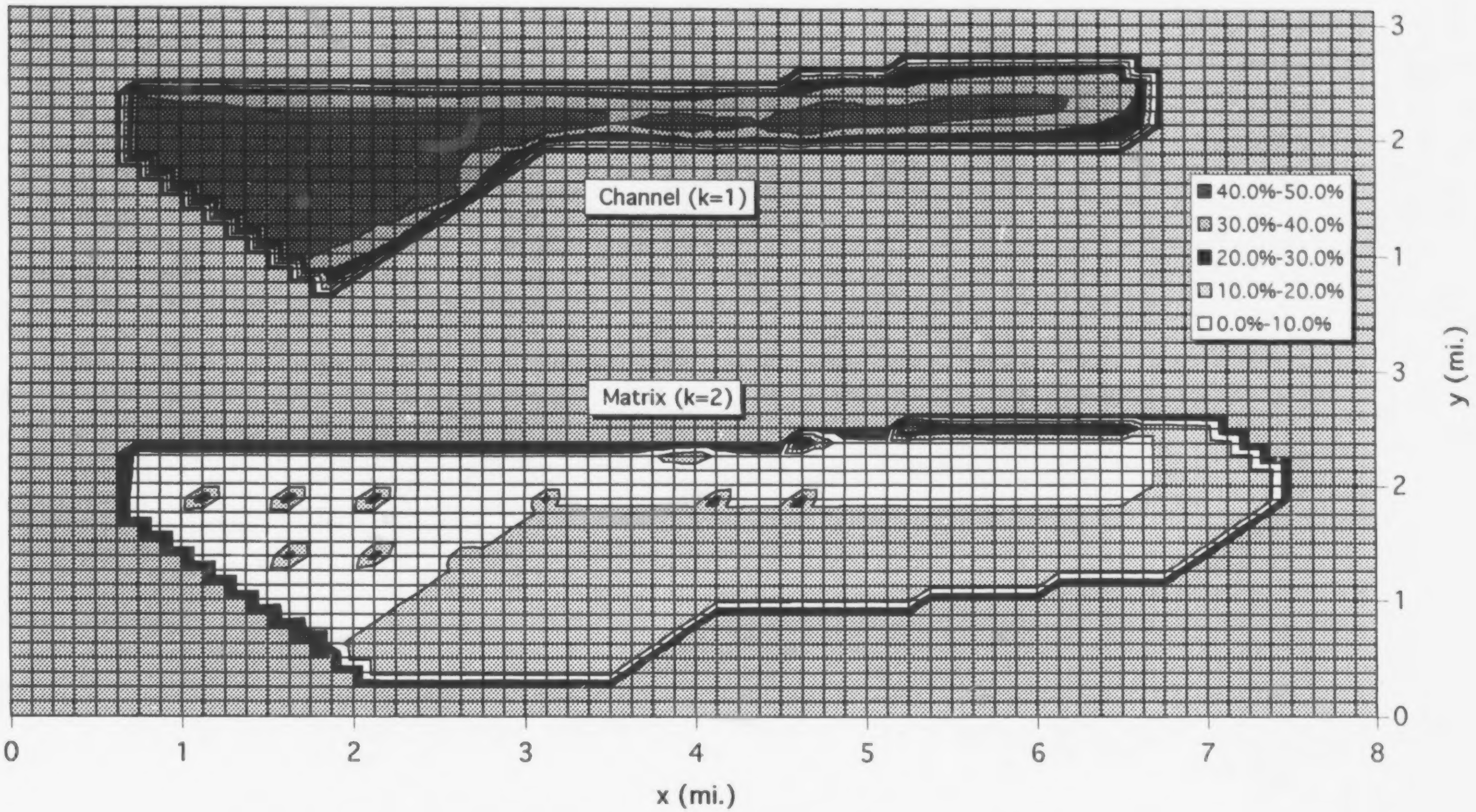


Figure 5.5(d): Primary (Oct-07) Gas Saturation S_g

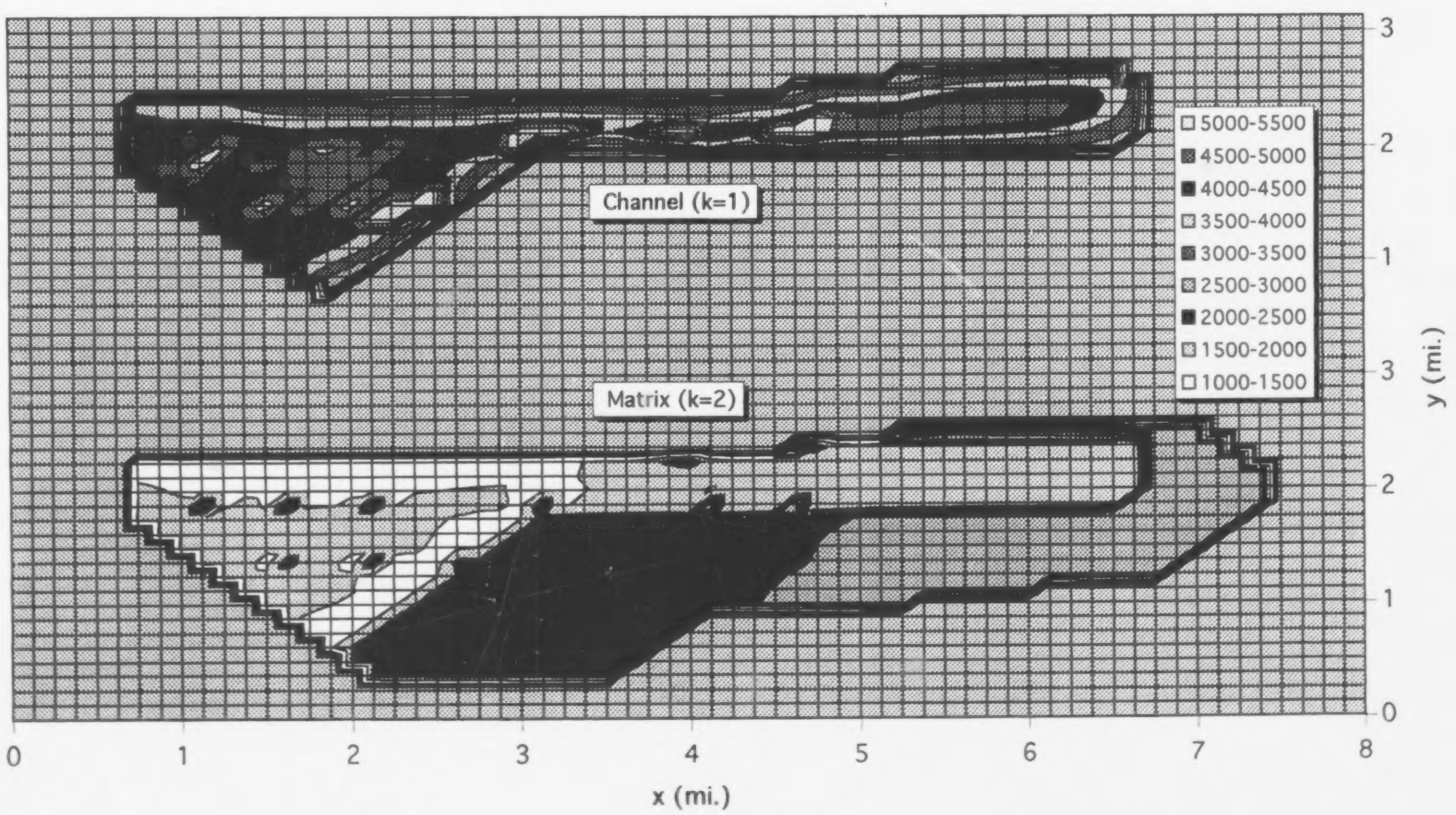


Figure 5.5(e): Primary (Oct-07) Bubble Point Pressure p_b (psia)

Chapter 6: Secondary Forecast

6.1 Waterflood Design

Waterflood design depends on the flood scheme. Schemes are classified by the main direction of displacement in either vertical or horizontal planes. A combination of vertical and horizontal processes can apply in dipping reservoirs. Vertical schemes inject water into wells completed at the bottom of the formation and produce oil from wells completed at the top. Horizontal schemes inject water into a pattern of wells and produce oil from wells completed in between. Commonly used patterns include:

- five-spot
- inverted nine-spot
- line drive
- peripheral

Some strategies will flood all pattern spacing units simultaneously. This requires a lump sum capital expense to drill and equip all wells in advance. Other strategies may stage the waterflood by sequentially flooding an emerging pattern in a predetermined sweep direction. Producers that flood out can be converted to injectors in adjacent pattern spacing units. The main advantage of the staged waterflood strategy is that capital is expensed in time with expanding operations. The main disadvantage is that production revenues are delayed over an extended project duration.

Waterflooding is an irreversible process. Once water communication is established between injectors and producers, water will preferentially flow through the pattern spacing unit. Existing producers will gradually flood out after water breaks through. Further pattern refinement through infill drilling may be inefficient. In some cases, infill drilling has been effective with pattern inversion. The pattern spacing and coverage must therefore be fixed at design time.

Waterflood response has a dependence on the primary depletion state. A waterflood strategy with a fixed pattern design is tailored to a particular primary depletion state at a particular point in time. The same waterflood may or may not perform as well for other primary depletion states. The decision process defines rules for choosing the fixed design at different times over primary decline.

A ten year timing window for pattern waterflood is assumed to open up within one year (1-Oct-95). This timing window corresponds to the admissible depletion states remaining in the twenty year life planned for primary production. The waterflood design is refined manually to improve potential response at the earliest feasible depletion state (1-Oct-95). Good production practice is assumed to apply for a twenty year pattern waterflood.

A five-spot pattern waterflood is chosen with a 40-acre spacing based on the minimum allowed by regulation. Simultaneous operation is selected to expedite the project. The proposed 34 well waterflood project with 23 infill wells are listed in Table 6.1 and mapped geographically in Figure 6.1(a). Figure 6.1(b) shows the 40-acre infill well spacing on the 10-acre reservoir grid overlay. Assignment of injectors and producers in the five-spot pattern are shown in Figure 6.1(c). A water barrier is placed on the eastern edge of the project to isolate the waterflood from the gas cap. The purpose of the barrier is to eliminate gas interference from the gas cap and maintain pressure in the project. The gas will be cut off at the high permeability channel pass.

Alternating rows of production and injection wells make up the five spot pattern. The number of wells were varied and the pattern shifted areally over the reservoir domain to obtain the best sweep of the oil rich zone. The placement of additional wells on the north and south boundary of the project had little effect on project recovery and were not included. Production wells on the north and south peripheral rows drained thinning boundary pay zones. Water displaced oil from the two injection rows placed between production rows. This configuration with 16 injectors and 18 producers gave a reduced set of wells to efficiently sweep the zone in an acceptable length of time.

6.2 Secondary Controls

The model waterflood is scheduled to start on 1-Oct-1995 and terminate at the end of a planned 20 year life on 1-Oct-2015. Only the wells in the design waterflood project are assumed to be in operation. Individual producers are designated to be permanently shut in if the oil rates fall below 10 STB/day or the water-oil ratio exceeds 20 STB/STB.

The secondary control policy described in Section 3.8 was implemented. Good production practice chooses to initially limit aggregate oil and gas production, and allow water injection to repressurize the reservoir above the bubble point pressure. Water injection was continuously maintained at maximum admissible rates (Eqns 3.10-12) over the duration of the project. All wells operating with saturated bottomhole conditions were pooled into one control group, while the remaining wells were treated as single control entities. These were continuously produced at maximum admissible rates (Eqns 3.7-3.9) while corresponding local bottomhole conditions remained above the bubble point pressure. Single control entities were reclassified and demoted to the aggregate control group, when the bottomhole condition switched from undersaturated to saturated states. An accounting system similar to that described for pooled primary control in Section 5.1 was used to regulate oil and gas production from the control group. In-house MRL and GOR assignments were established on the basis of an implicit utility function. It was assumed that corporate head office would demand an initial waterflood revenue stream to be at least as much as that expected from continued primary production. The base GOR=1.129 Mscf/STB that applied for primary operations was chosen for the aggregate control group. An aggregate MRL=1600 STB/day for the control group was determined by waterflood forecasting through trial and error. These values provided a repressurization policy which met undersaturated objectives within 1-6 years and provided initial waterflood revenues that satisfied the revenue utility demand. A single lumped production cycle was determined by the aggregate maximum admissible oil and gas production rates. In house gas quotas had precedence over oil quotas. Relevant wells were simultaneously, and collectively, toggled on and off while assigned to the control group. Wells that repressured above the bubble point were promoted to single control entity status and allowed to produce at maximum rates. Individual production wells were regulated over the course of waterflood, either independently or within a group, to attain the objectives set forth.

Monthly production accounts were accumulated for each well. Each well in the control group tracked the same monthly production hours. Cycle-averaged oil, gas and water rates were calculated for each well by dividing accumulated monthly production accounts by the corresponding hours of production. Cycle-averaged production rates were recorded for the current month at the end of the monthly cycle. Calendar time was used for each month. Instantaneous aggregate pool production rates and average reservoir pressure were recorded at each time step. Instantaneous bottomhole pressures for each well were also recorded at each time step.

6.3 Waterflood Simulation

Figures 6.2(a)-(r) shows monthly production forecasts for the eighteen production wells. Half the wells start producing at maximum pump capacity. Some wells exhibit cyclic switching from bang-bang control to continuous control as bottomhole conditions oscillate about the bubble point pressure. Individual well repressurization objectives are met within 1-6 years and water breakthroughs occur within 3-15 years. Monthly cycle bandwidths in production hours increase as production rates decline. Some wells flood out early and are permanently shut in.

Figures 6.3(a)-(p) shows monthly water injection forecasts for the sixteen injection wells. Injection rates initially drop as radial flow fronts interact with reservoir fluids. Injection rates then rise as water displaces or dissolves free gas and fills its pore space. Injection rates continue to rise until water breaks through at adjacent producing wells. Injection rates fall after water breakthrough and the reservoir floods out with increasing pressure. Underground water flows are diverted towards other producing wells as high water-oil producers are shut in.

Figure 6.4(a) shows an increasing trend in average reservoir pressure as it exceeds bubble point pressures. Figure 6.4(b) shows the cumulative oil, gas and water production predicted for the entire pool. Seven production wells have flooded out. Figure 6.4(c) shows the cumulative water injection predicted for the entire pool. Figures 6.5(a)-(c) show the predicted instantaneous pooled oil gas and water production rates, respectively. Pooled cycles correspond to the sum total of individual well cycles, some operating continuously and others under bang-bang control. The envelopes for pooled oil and gas rate display typical waterflood response. The pooled water production rate drops stepwise as producers flood out and are shut in. Figure 6.5(d) shows predicted instantaneous pooled water injection rates. The pooled water injection rate also shows a typical waterflood response.

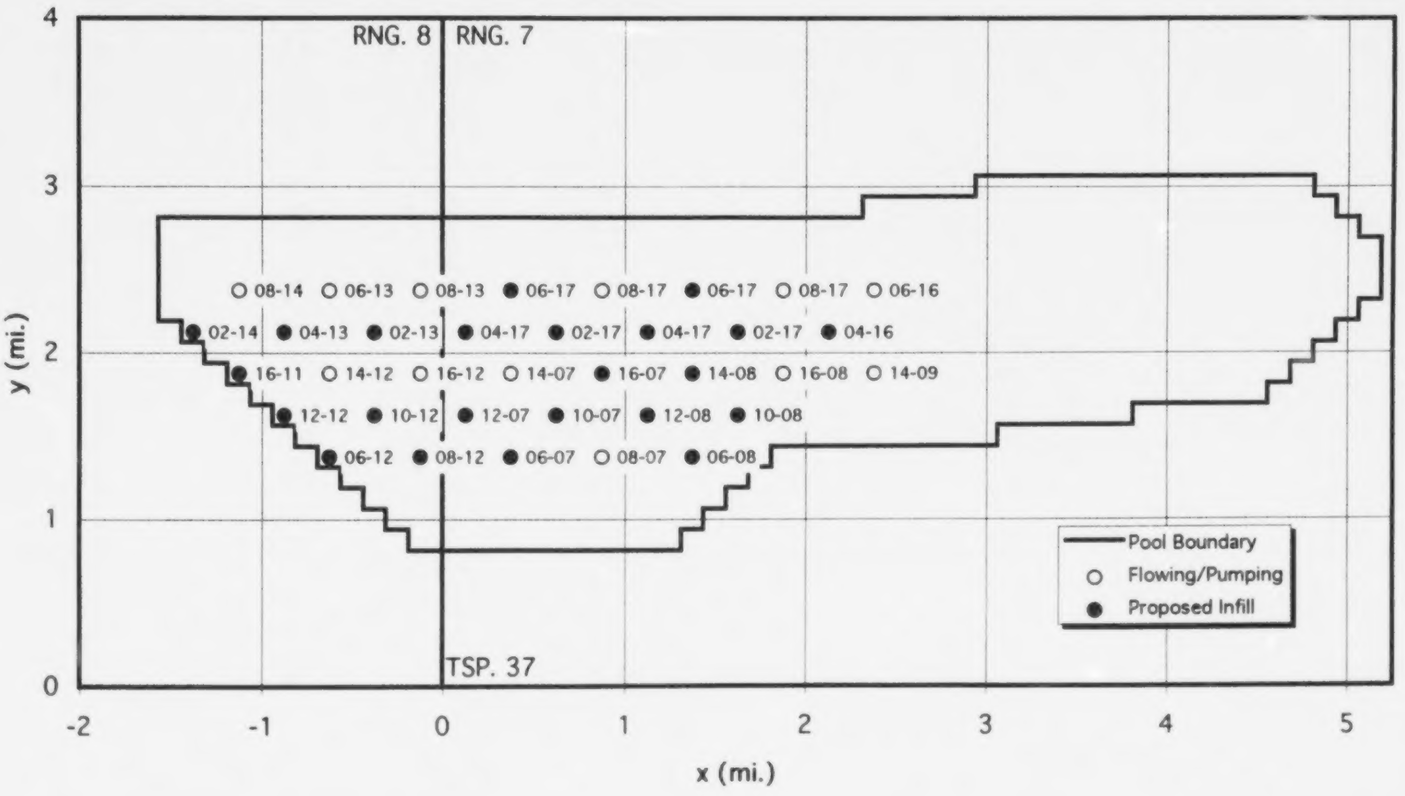
Figures 6.6(a)-(e) show the predicted reservoir depletion state after twelve years of waterflooding (Oct-07). This time coincides with the end of the planned primary period. The reservoir is highly repressurized except for a low pressure gas zone persisting at the southern boundary as shown in Figures 6.6(a)and(d). This area is adjacent to the Viking "B" pool and has low permeability. The gas cap has been compressed back into solution. Figure 6.6(b) shows high water saturations distributed over the waterflood project region. Most of the region has flooded out. A few remaining wells are experiencing water breakthrough. The water barrier has effectively isolated the project region. Figure 6.6(c) shows that the region flooded out is at residual oil saturation (17.5%). High oil saturations remain in thin boundary edges and in the region occupied by the receding gas. The bubble point pressure distribution in Figure 6.6(e) shows that the remaining oil in the waterflood region has become more concentrated in heavier ends.

6.4 Waterflood Design Summary

Waterflood depletion forecasted large amounts of oil recovered over the planned waterflood life. The current state of operation had historically recovered 0.89 MMSTB over seven years of primay production (1-Oct-94). Another 0.21 MMSTB was forecast for one year of continued primary operation (1-Oct-95). The original oil in place was estimated as 25.4 MMSTB in the reservoir model. Predicted waterflood recovery was 9.8 MMSTB to give a forecasted secondary recovery factor of 38.6% and a total recovery factor of 42.8%. Cumulative water injected was 24.2 MMSTB and cumulative water produced was 6.6 MMSTB. The expectation of high secondary recovery for the proposed waterflood design justifies an economic evaluation with option timing analysis.

	Chedderville Viking A Proposed Waterflood with Infill Wells					
Well	LSD	SEC	TWP	RGE	W	STATUS
1	6	7	37	7	5	INFILL
2	10	7	37	7	5	INFILL
3	12	7	37	7	5	INFILL
4	16	7	37	7	5	INFILL
5	6	8	37	7	5	INFILL
6	10	8	37	7	5	INFILL
7	12	8	37	7	5	INFILL
8	14	8	37	7	5	INFILL
9	4	16	37	7	5	INFILL
10	2	17	37	7	5	INFILL
11	4	17	37	7	5	INFILL
12	6	17	37	7	5	INFILL
13	2	18	37	7	5	INFILL
14	4	18	37	7	5	INFILL
15	6	18	37	7	5	INFILL
16	16	11	37	8	5	INFILL
17	6	12	37	8	5	INFILL
18	8	12	37	8	5	INFILL
19	10	12	37	8	5	INFILL
20	12	12	37	8	5	INFILL
21	2	13	37	8	5	INFILL
22	4	13	37	8	5	INFILL
23	2	14	37	8	5	INFILL
1	6	7	37	7	5	PRODUCTION
2	8	7	37	7	5	PRODUCTION
3	14	7	37	7	5	PRODUCTION
4	16	7	37	7	5	PRODUCTION
5	6	8	37	7	5	PRODUCTION
6	14	8	37	7	5	PRODUCTION
7	6	17	37	7	5	PRODUCTION
8	8	17	37	7	5	PRODUCTION
9	6	18	37	7	5	PRODUCTION
10	8	18	37	7	5	PRODUCTION
11	16	11	37	8	5	PRODUCTION
12	6	12	37	8	5	PRODUCTION
13	8	12	37	8	5	PRODUCTION
14	14	12	37	8	5	PRODUCTION
15	16	12	37	8	5	PRODUCTION
16	6	13	37	8	5	PRODUCTION
17	8	13	37	8	5	PRODUCTION
18	8	14	37	8	5	PRODUCTION
19	10	7	37	7	5	INJECTION
20	12	7	37	7	5	INJECTION
21	10	8	37	7	5	INJECTION
22	12	8	37	7	5	INJECTION
23	16	8	37	7	5	INJECTION
24	4	16	37	7	5	INJECTION
25	6	16	37	7	5	INJECTION
26	2	17	37	7	5	INJECTION
27	4	17	37	7	5	INJECTION
28	2	18	37	7	5	INJECTION
29	4	18	37	7	5	INJECTION
30	10	12	37	8	5	INJECTION
31	12	12	37	8	5	INJECTION
32	2	13	37	8	5	INJECTION
33	4	13	37	8	5	INJECTION
34	2	14	37	8	5	INJECTION

Table 6.1: Proposed Waterflood Project


RNG. 8
RNG. 7
TSP. 37
○ 08-14
○ 06-13
○ 08-13
● 06-17
○ 08-17
● 06-17
○ 08-17
○ 06-16
● 02-14
● 04-13
● 02-13
● 04-17
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● 04-17
● 02-17
● 04-16
● 16-11
○ 14-12
○ 16-12
○ 14-07
● 16-07
● 14-08
○ 16-08
○ 14-09
● 12-12
● 10-12
● 12-07
● 10-07
● 12-08
● 10-08
● 06-12
● 08-12
● 06-07
○ 08-07
● 06-08
Pool Boundary
○ Flowing/Pumping
● Proposed Infill
y (mi.)
4
3
2
1
0
x (mi.)
-2
-1
0
1
2
3
4
5

Figure 6.1(a): Chedderville Viking "A" Infill Drilling Location Map

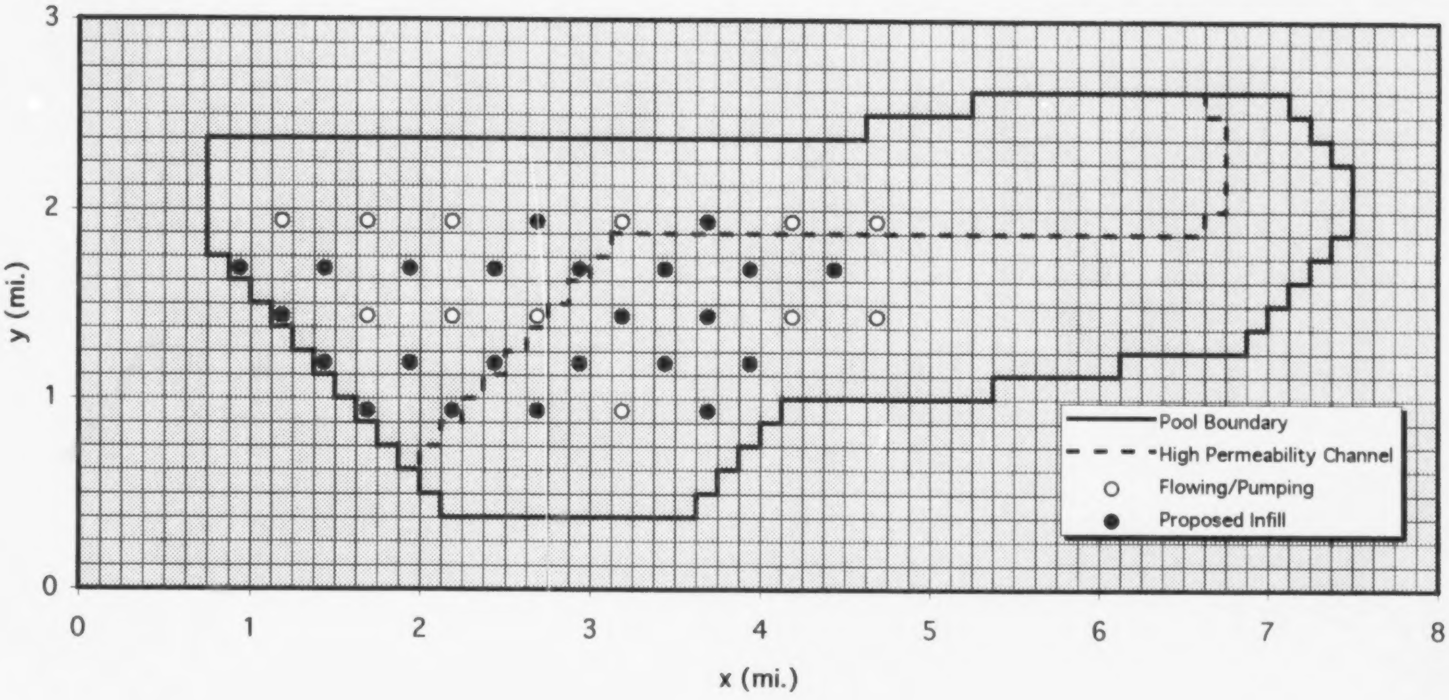
3
2
1
0
y (mi.)
0
1
2
3
4
5
6
7
8
x (mi.)
Pool Boundary
High Permeability Channel
Flowing/Pumping
Proposed Infill

Figure 6.1(b): Infill Drilling Grid (40-acre Spacing)

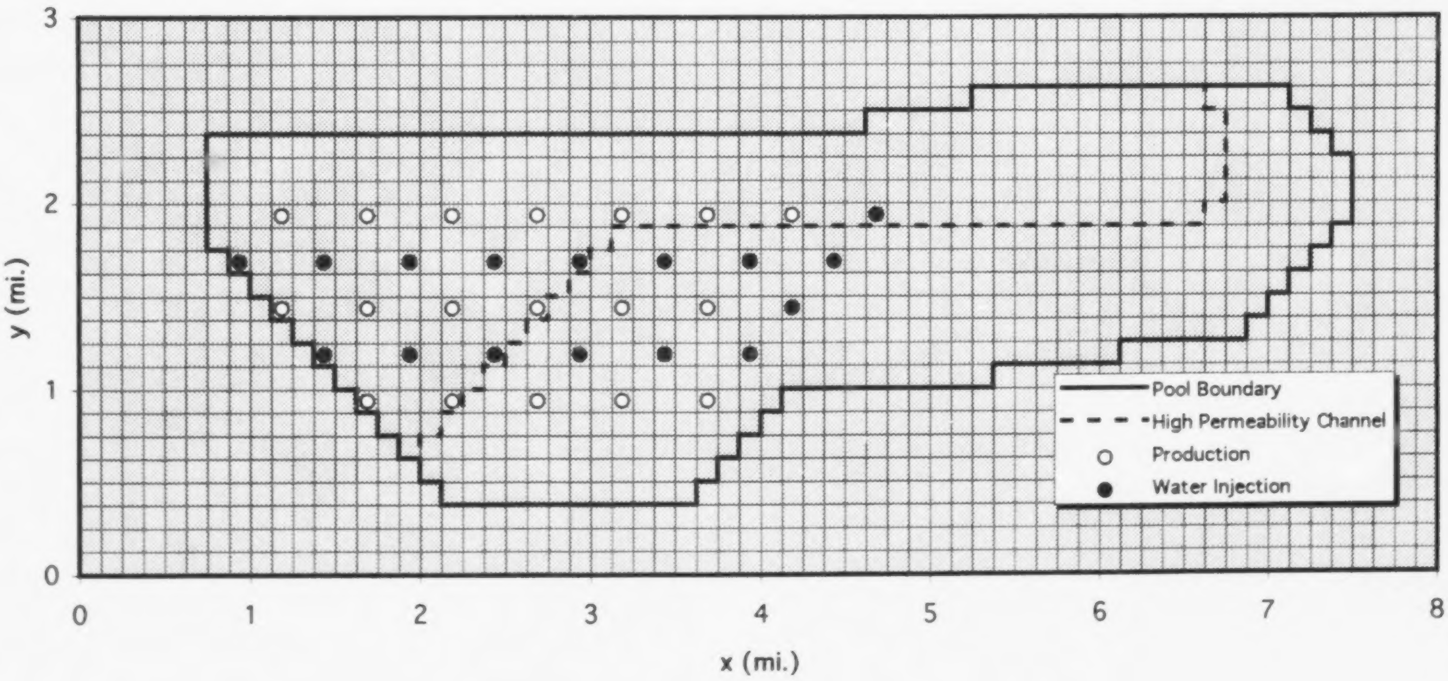

Figure 6.1(c): 5-Spot Pattern Waterflood with Water-Barrier

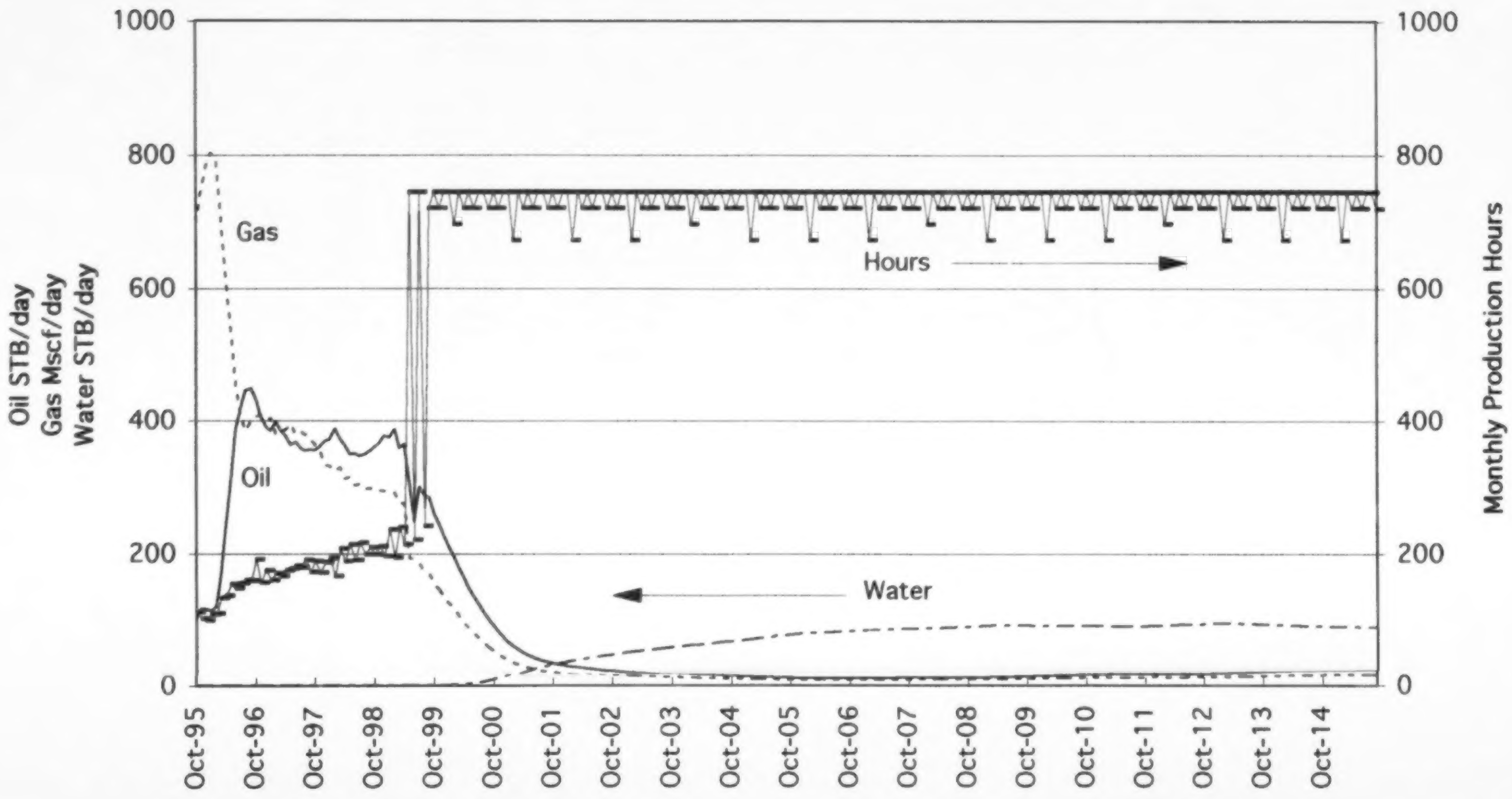

Figure 6.2(a): Waterflood Production Forecast (08-13-37-8W5)

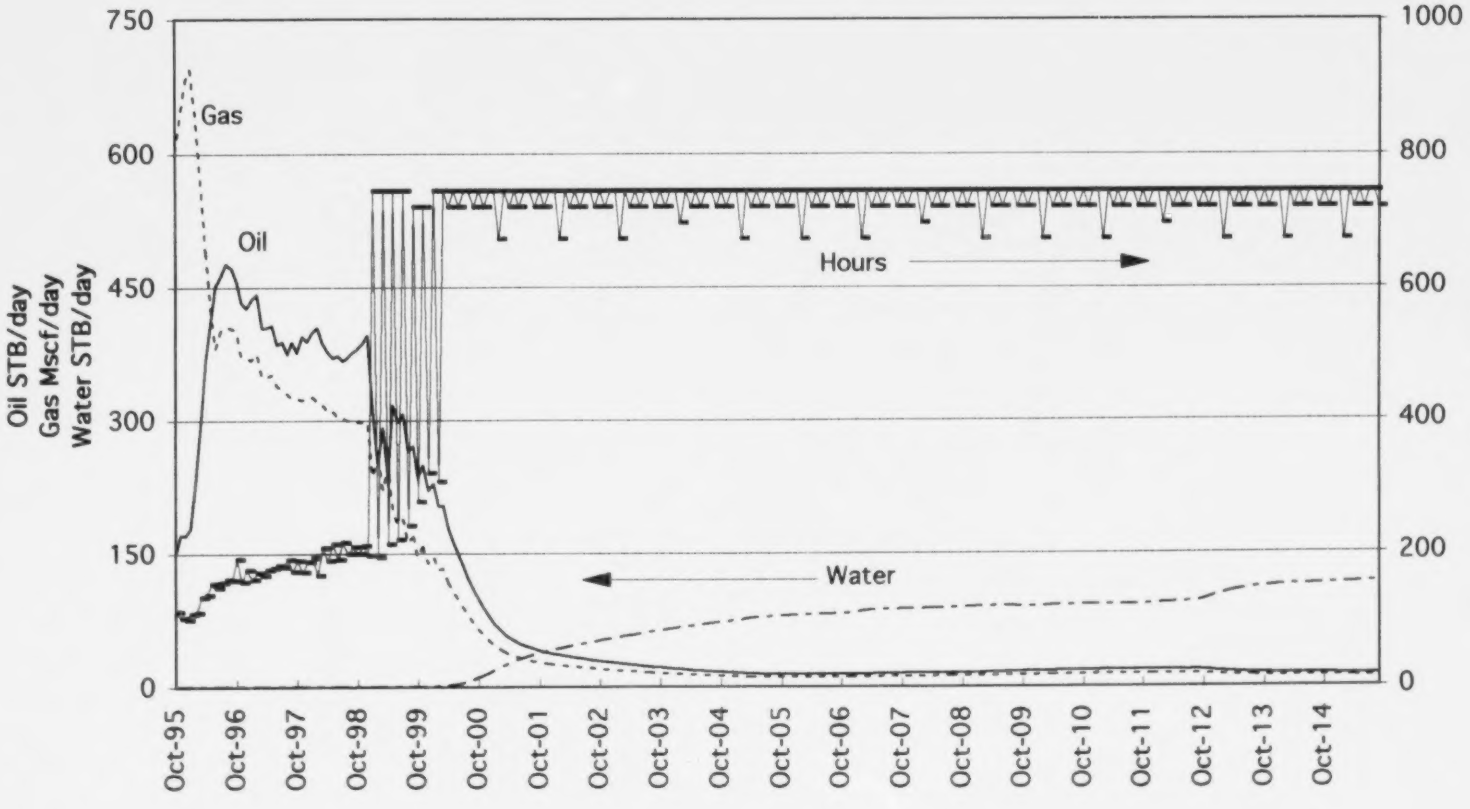

Figure 6.2(b): Waterflood Production Forecast (06-13-37-8W5)

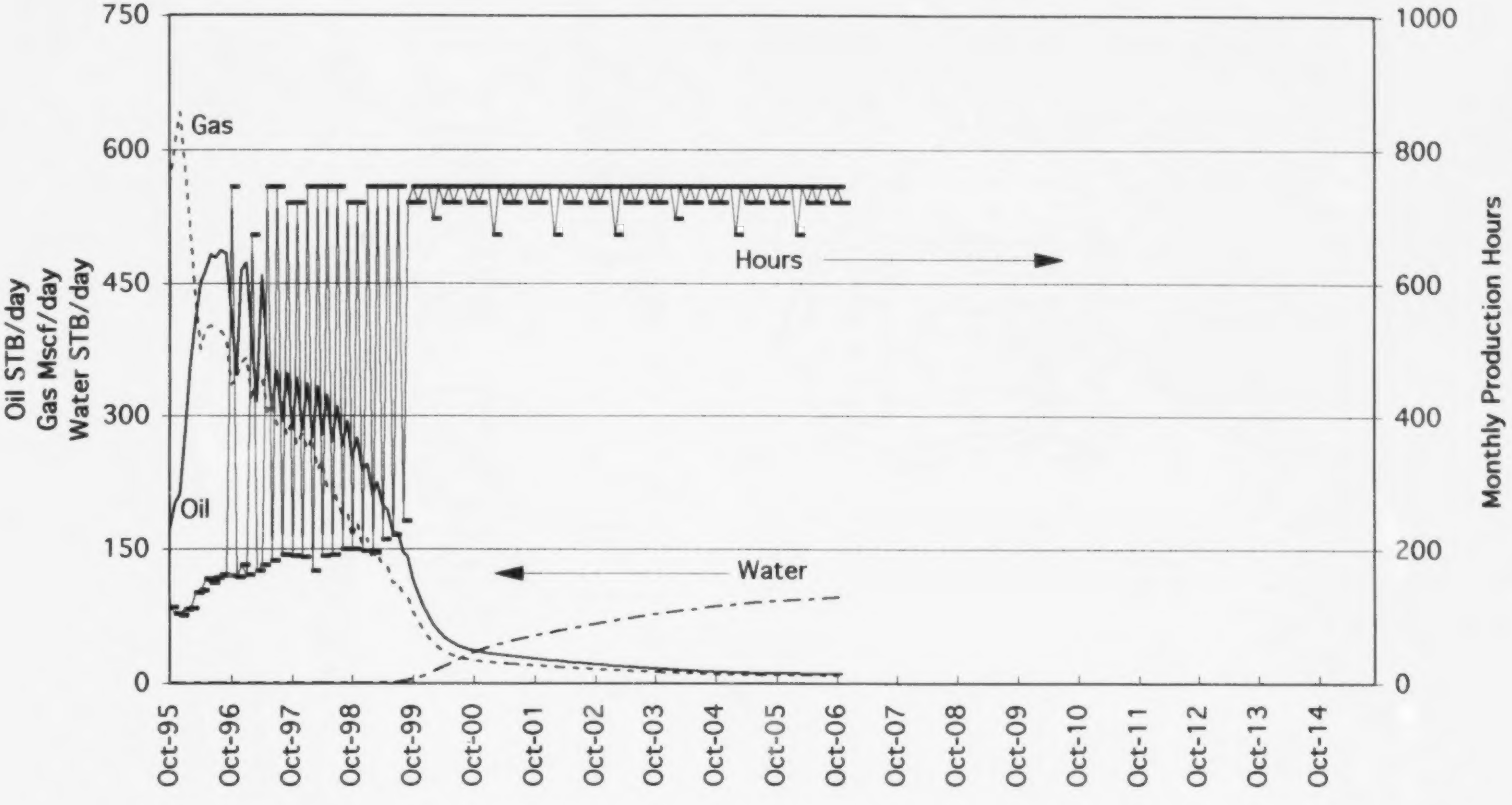

Figure 6.2(c): Waterflood Production Forecast (08-14-37-8W5)

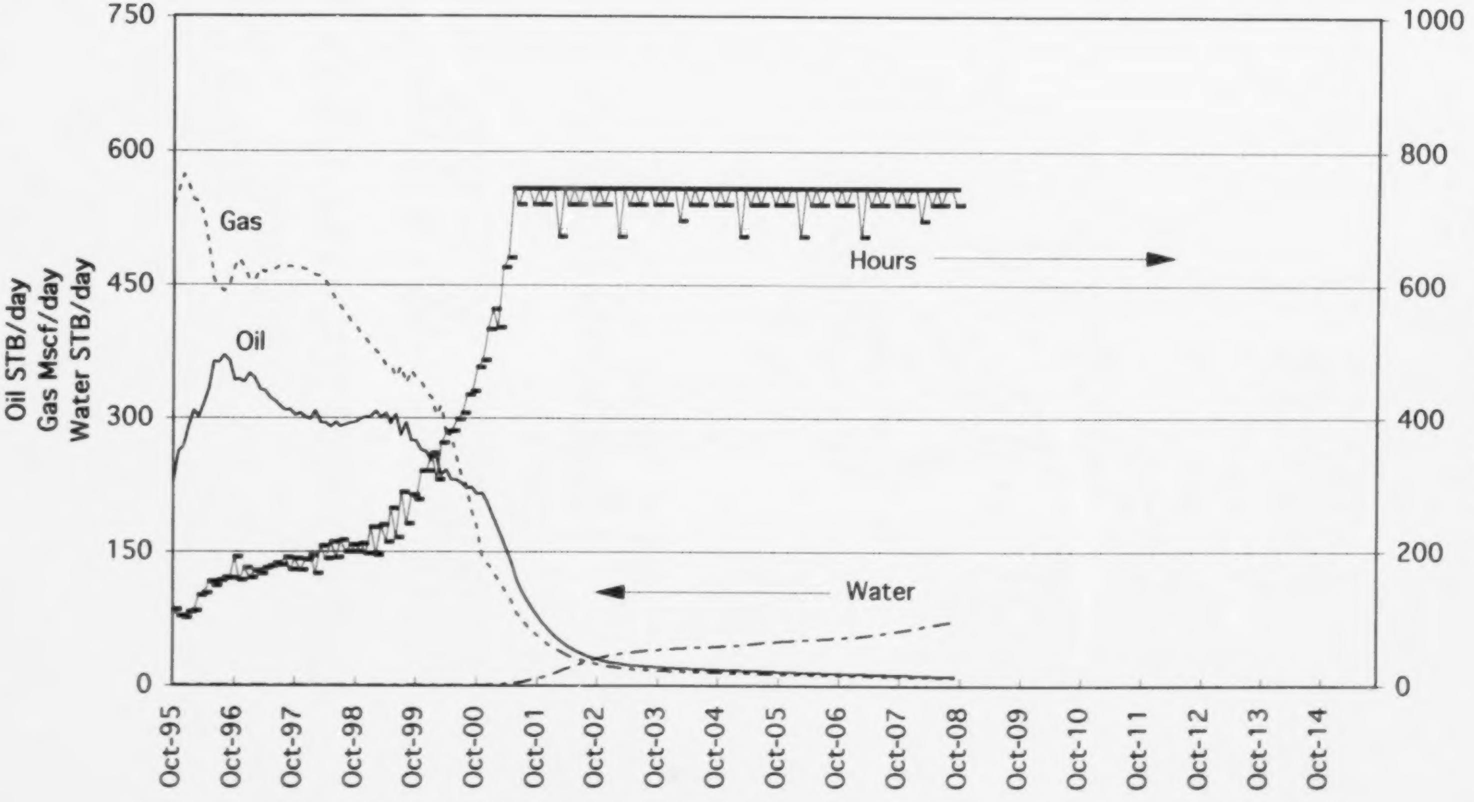

Figure 6.2(d): Waterflood Production Forecast (08-18-37-7W5)

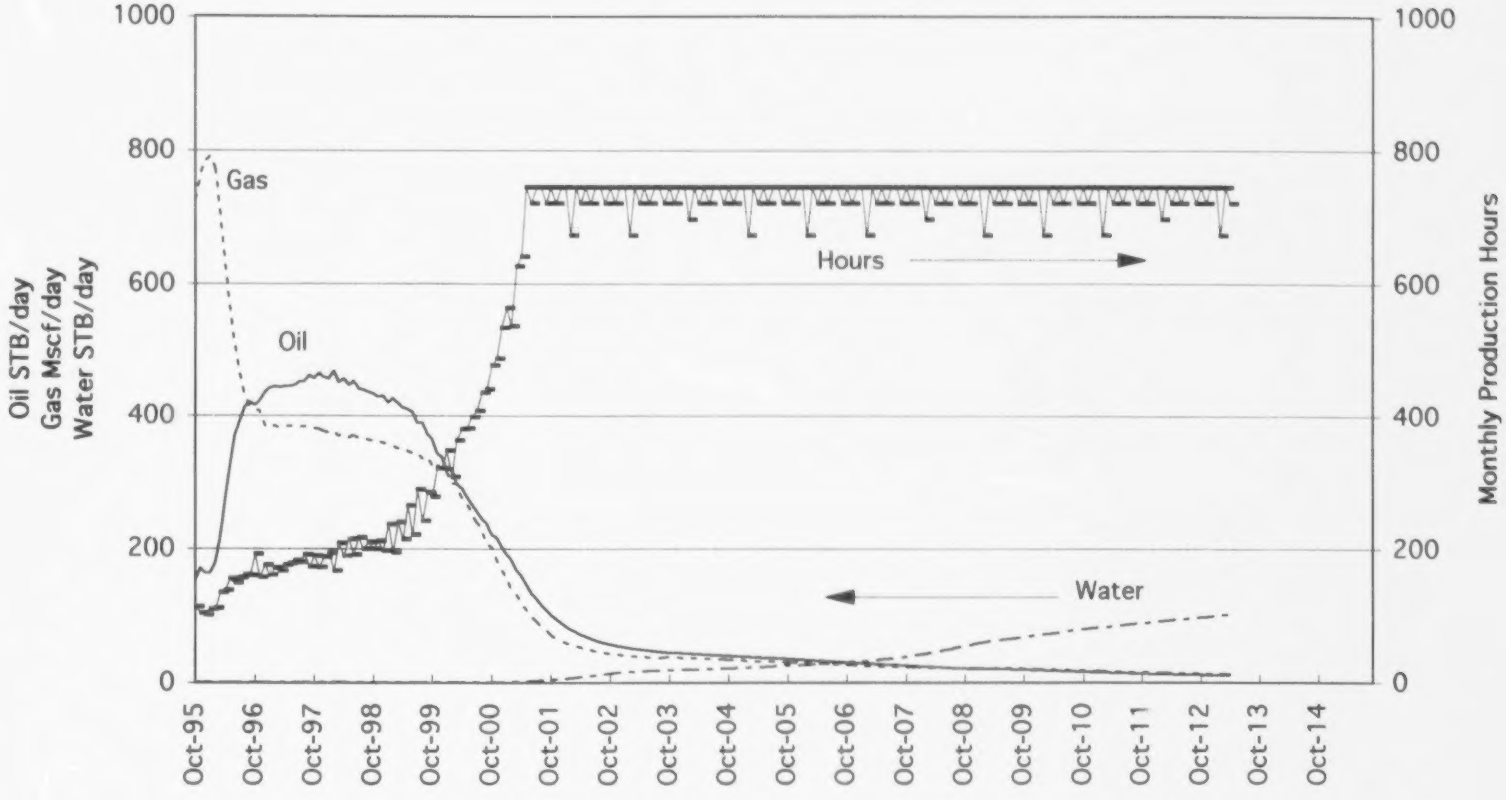

Figure 6.2(e): Waterflood Production Forecast (08-17-37-7W5)

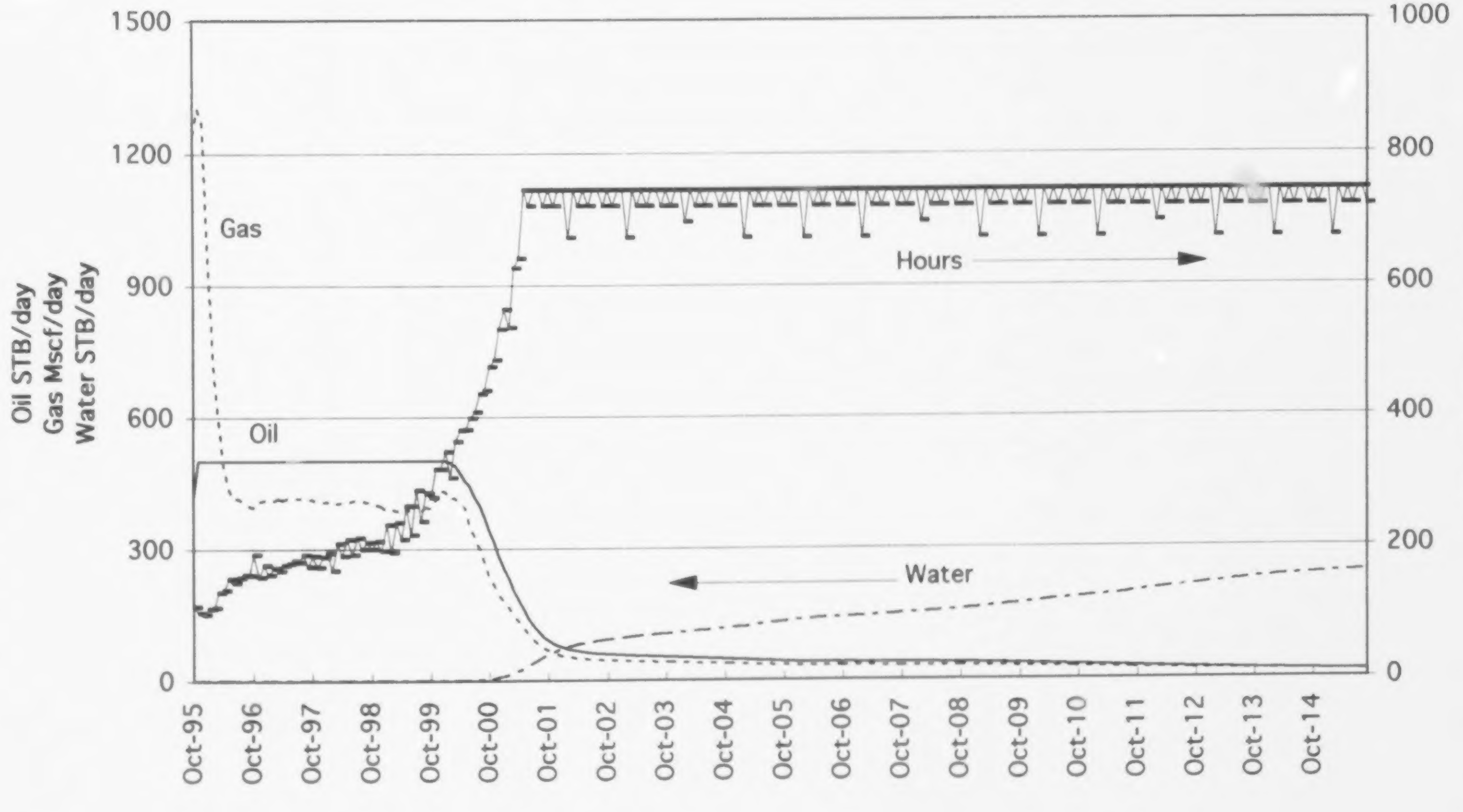

Figure 6.2(f): Waterflood Production Forecast (14-07-37-7W5)

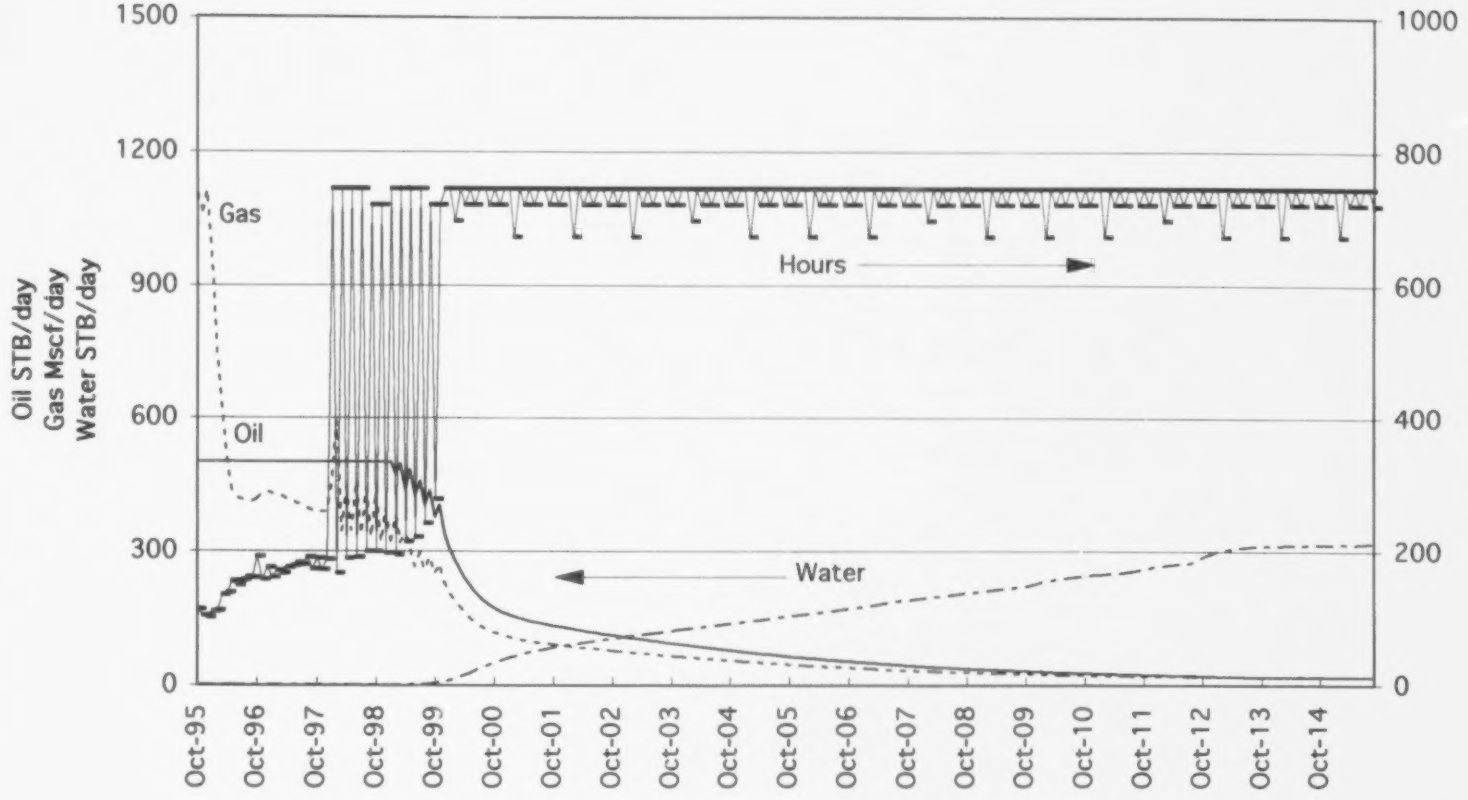

Figure 6.2(g): Waterflood Production Forecast (14-12-37-8W5)

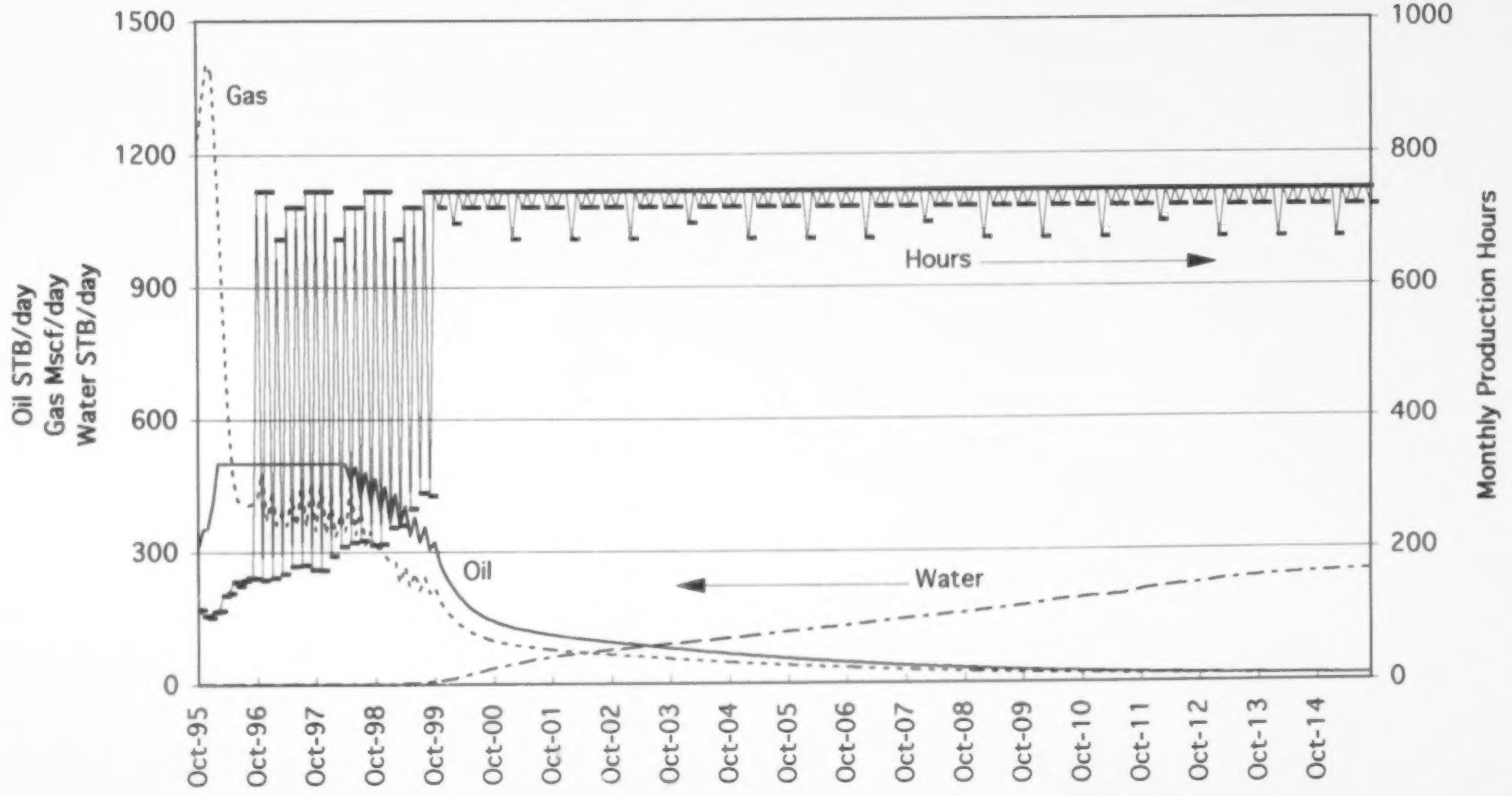

Figure 6.2(h): Waterflood Production Forecast (16-12-37-8W5)

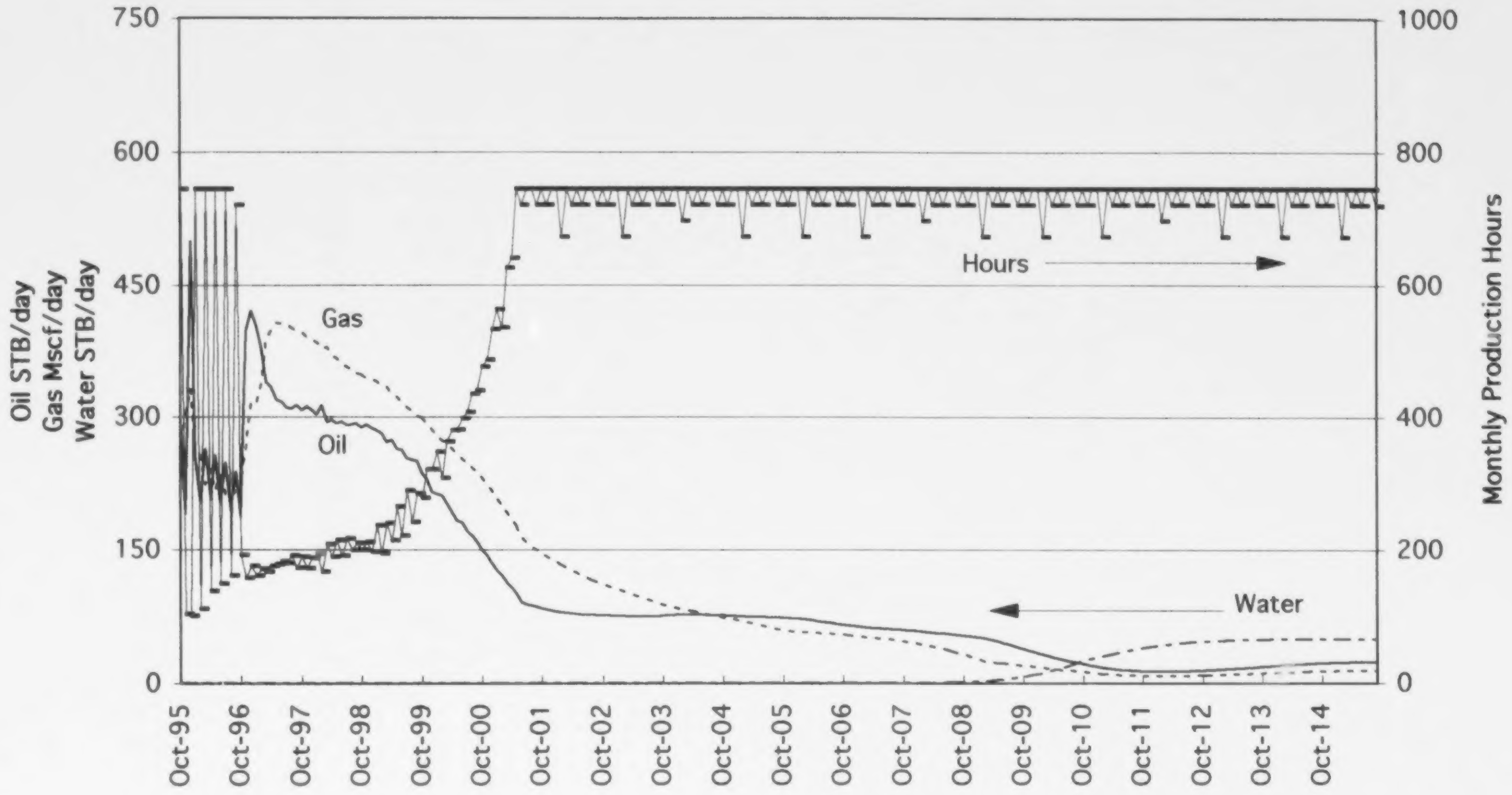

Figure 6.2(i): Waterflood Production Forecast (08-07-37-7W5)

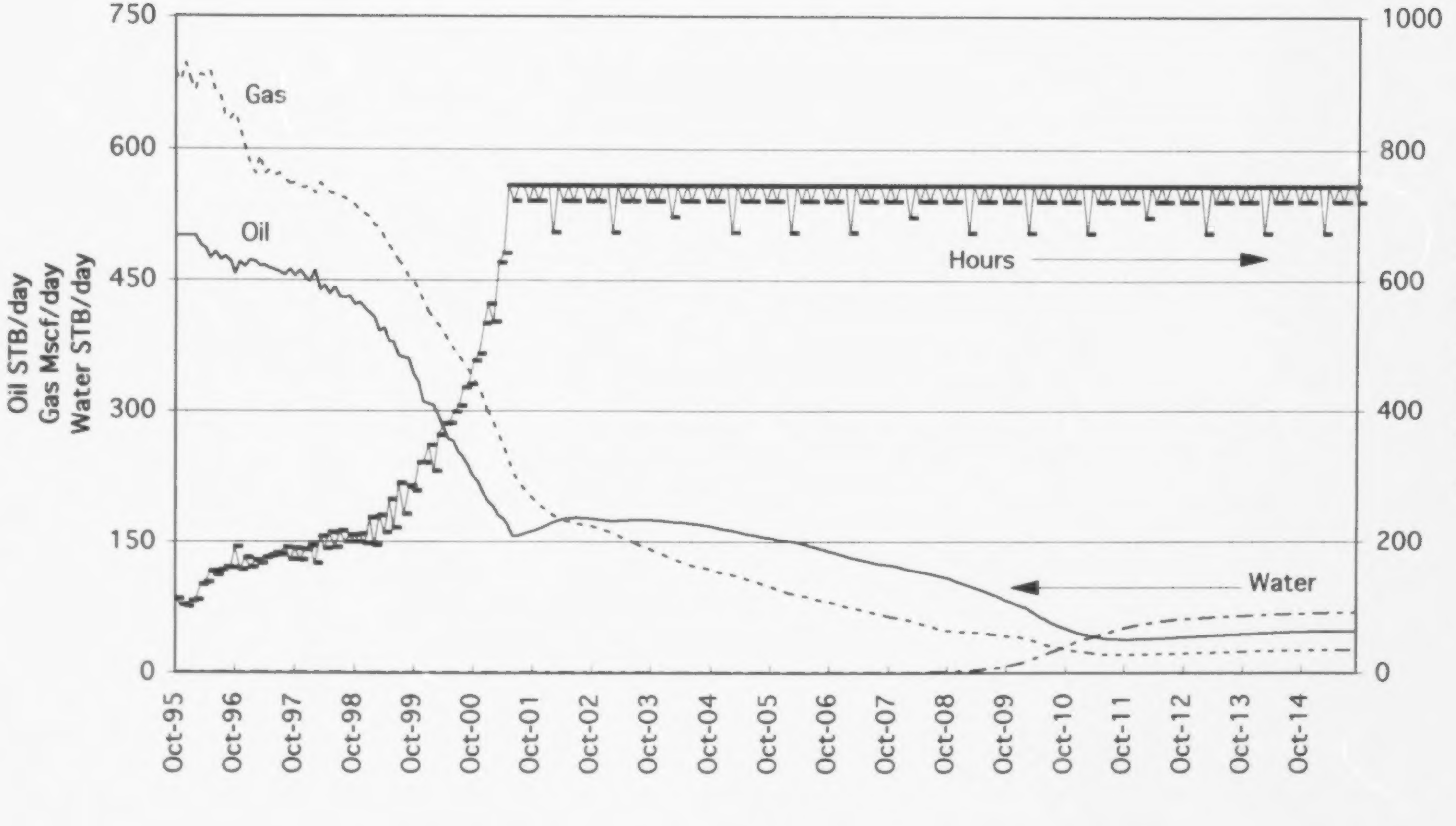

Figure 6.2(j): Waterflood Production Forecast (06-07-37-7W5)

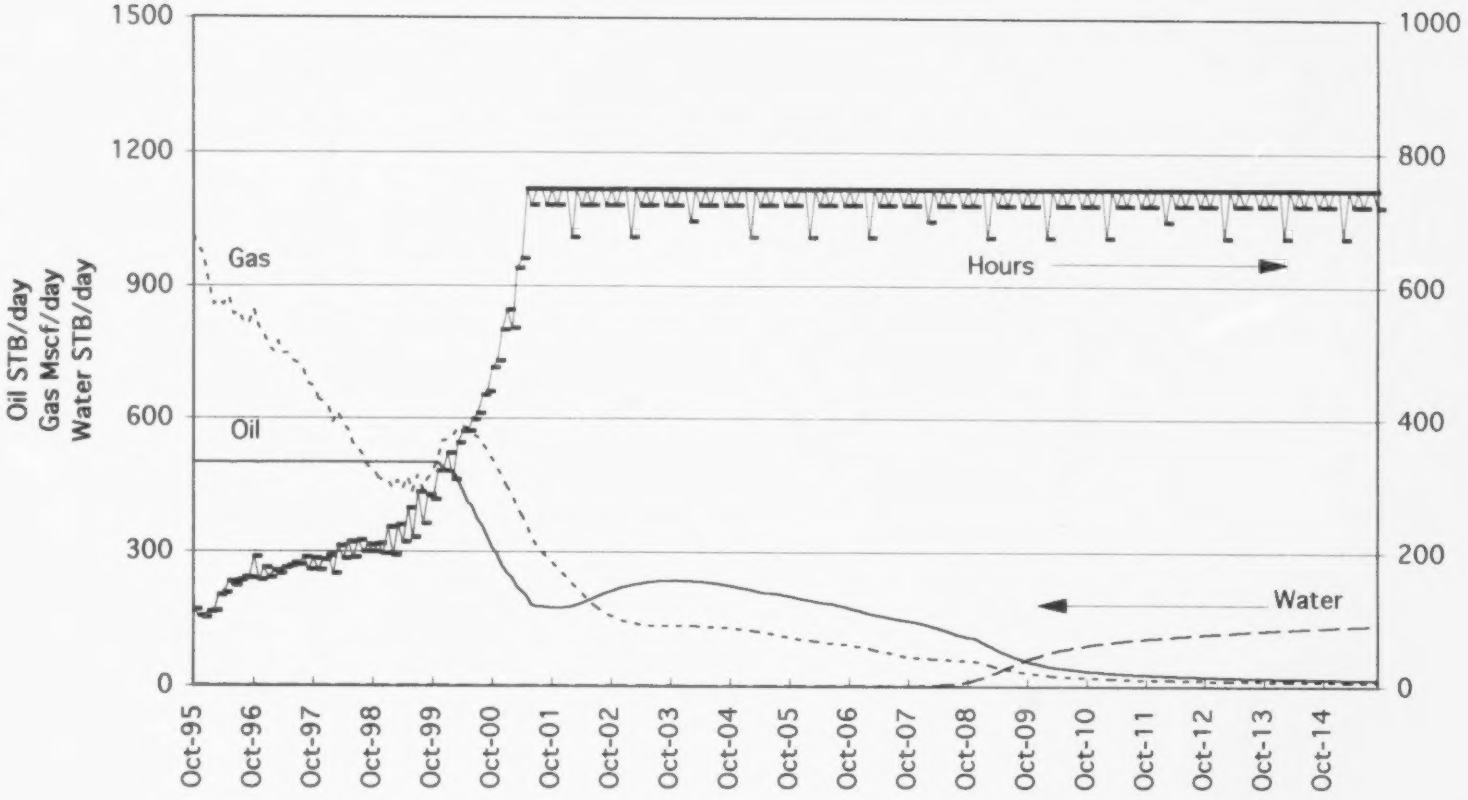

Figure 6.2(k): Waterflood Production Forecast (16-07-37-7W5)

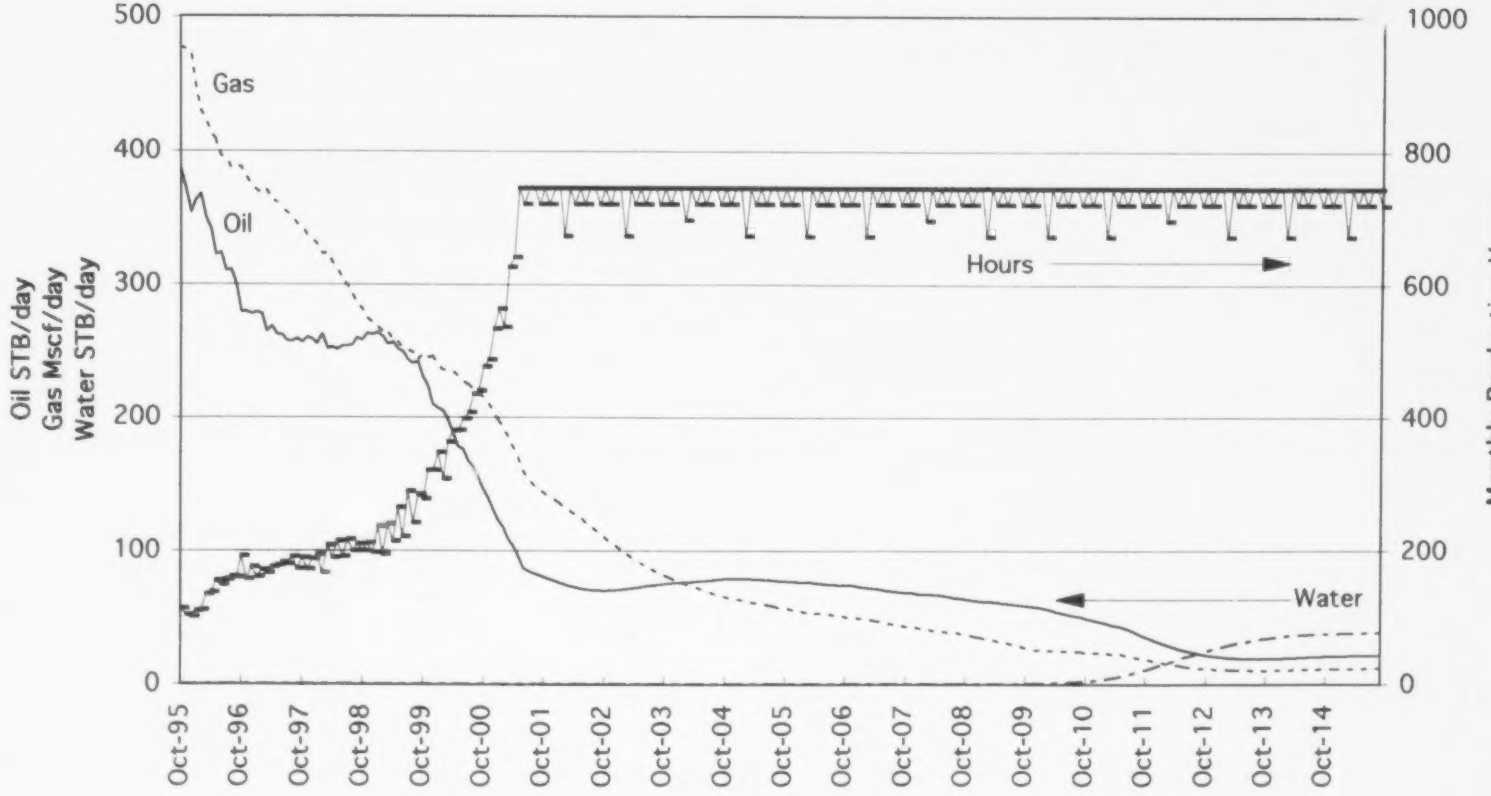

Figure 6.2(I): Waterflood Production Forecast (06-08-37-7W5)

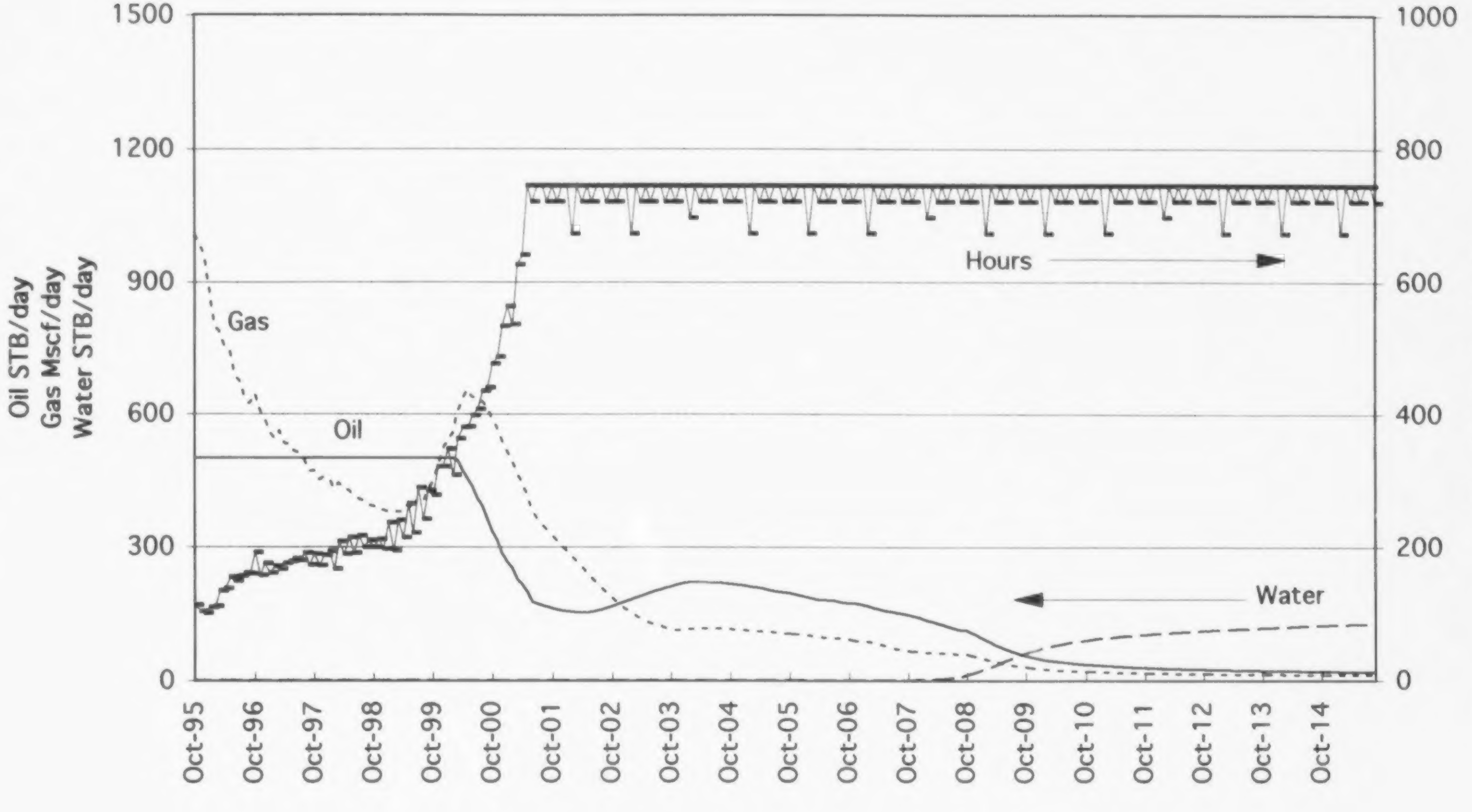

Figure 6.2(m): Waterflood Production Forecast (14-08-37-7W5)

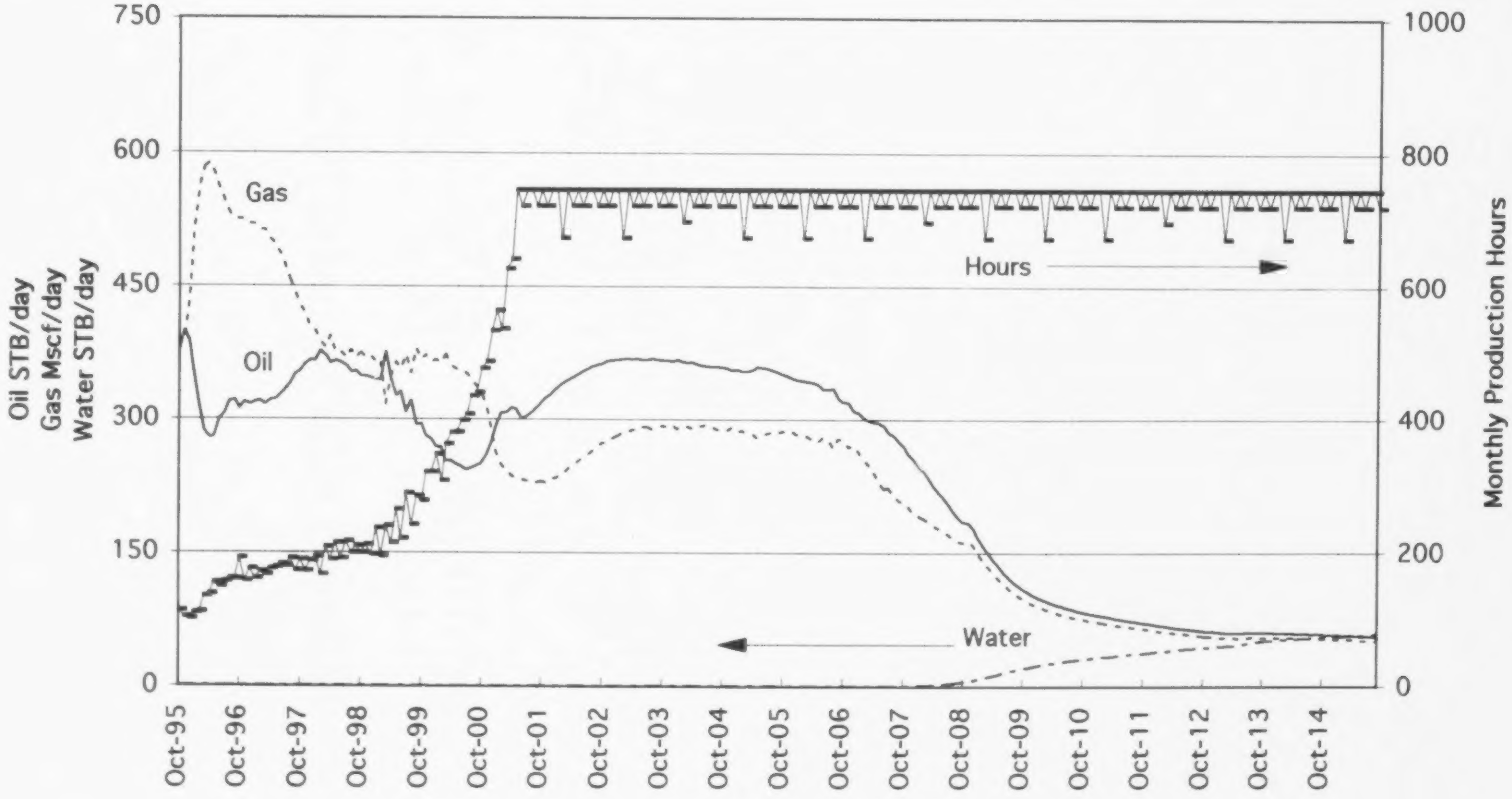

Figure 6.2(n): Waterflood Production Forecast (06-17-37-7W5)

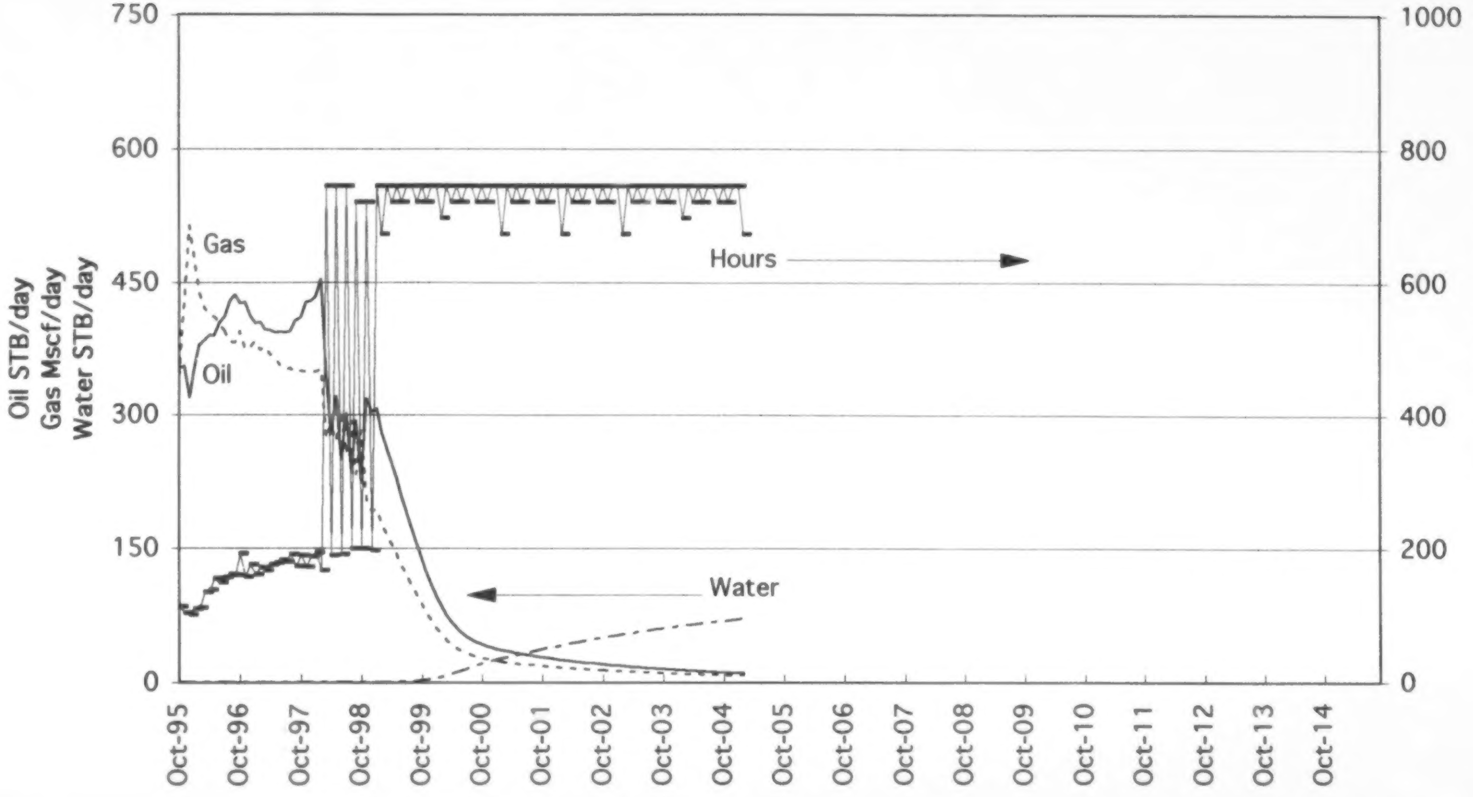

Figure 6.2(o): Waterflood Production Forecast (06-18-37-7W5)

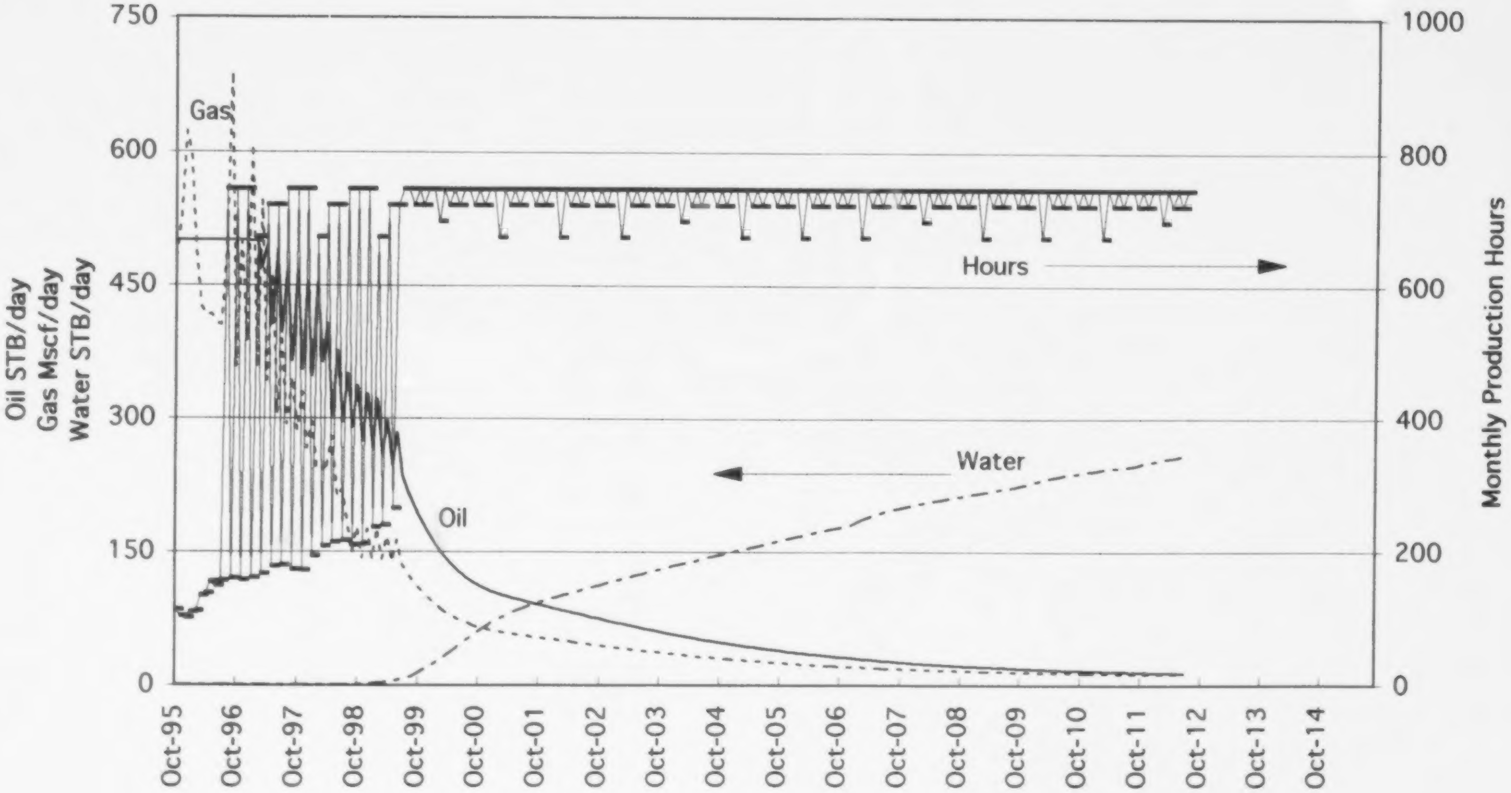

Figure 6.2(p): Waterflood Production Forecast (16-11-37-8W5)

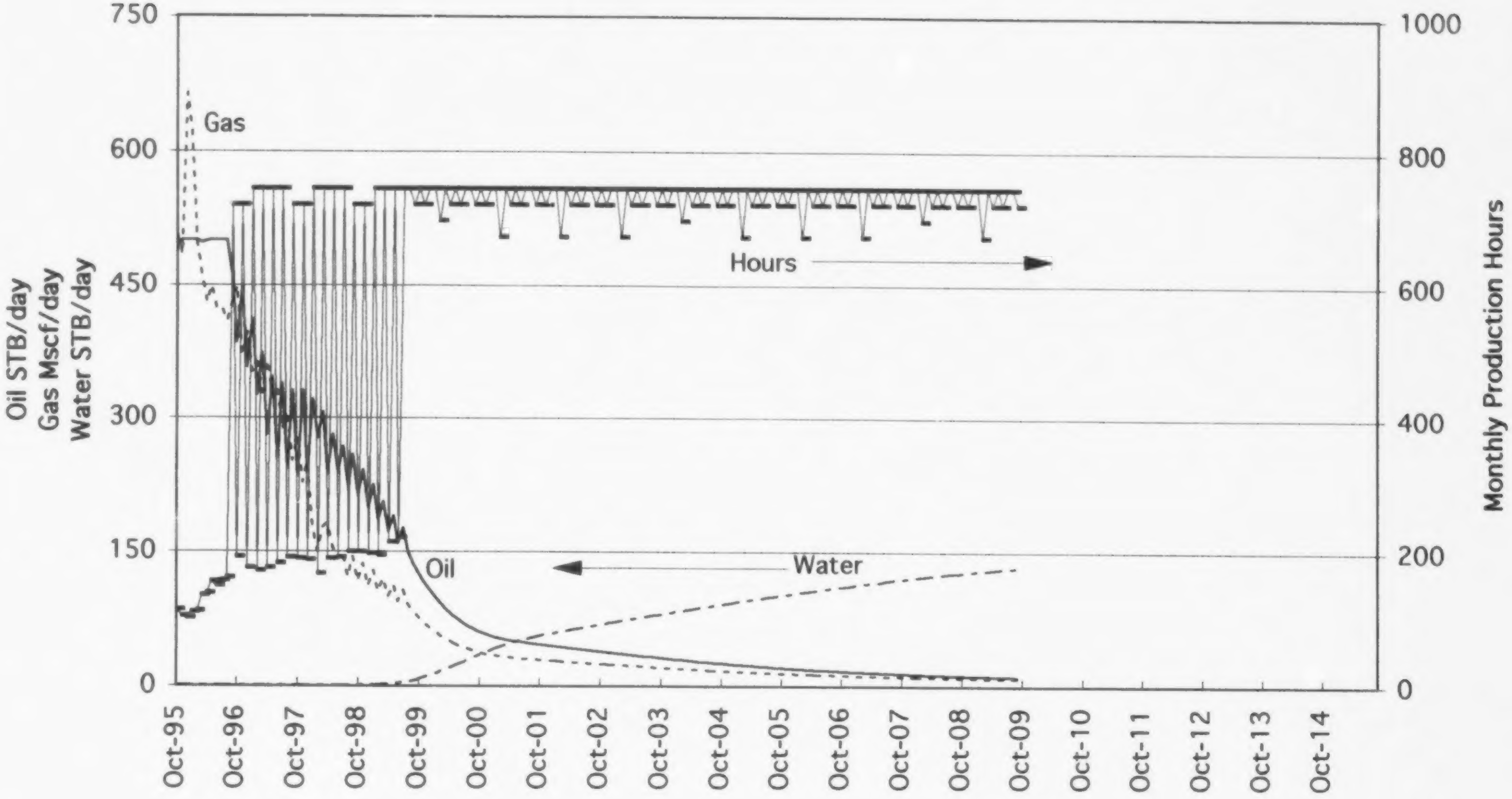

Figure 6.2(g): Waterflood Production Forecast (06-12-37-8W5)

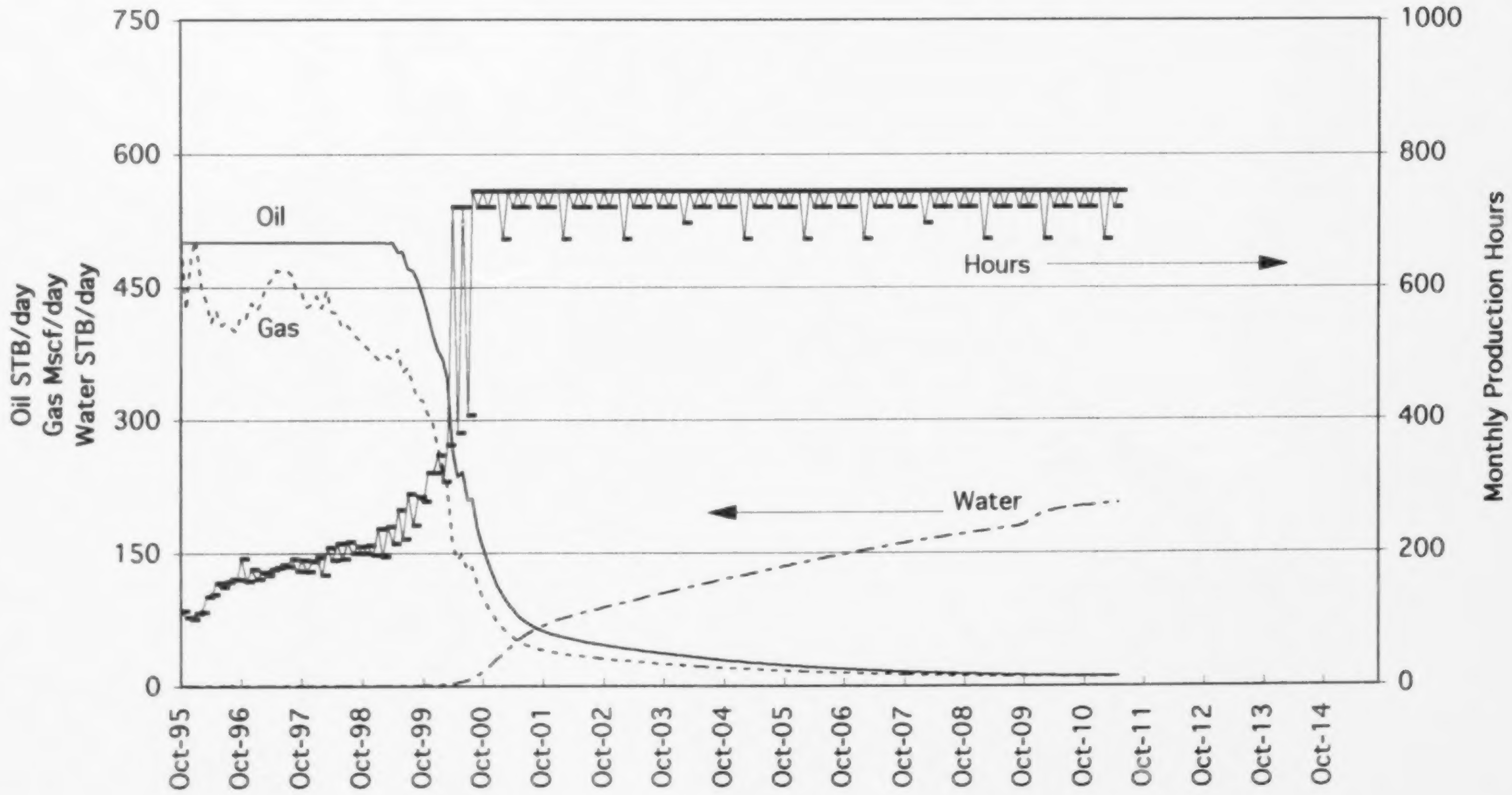

Figure 6.2(r): Waterflood Production Forecast (08-12-37-8W5)

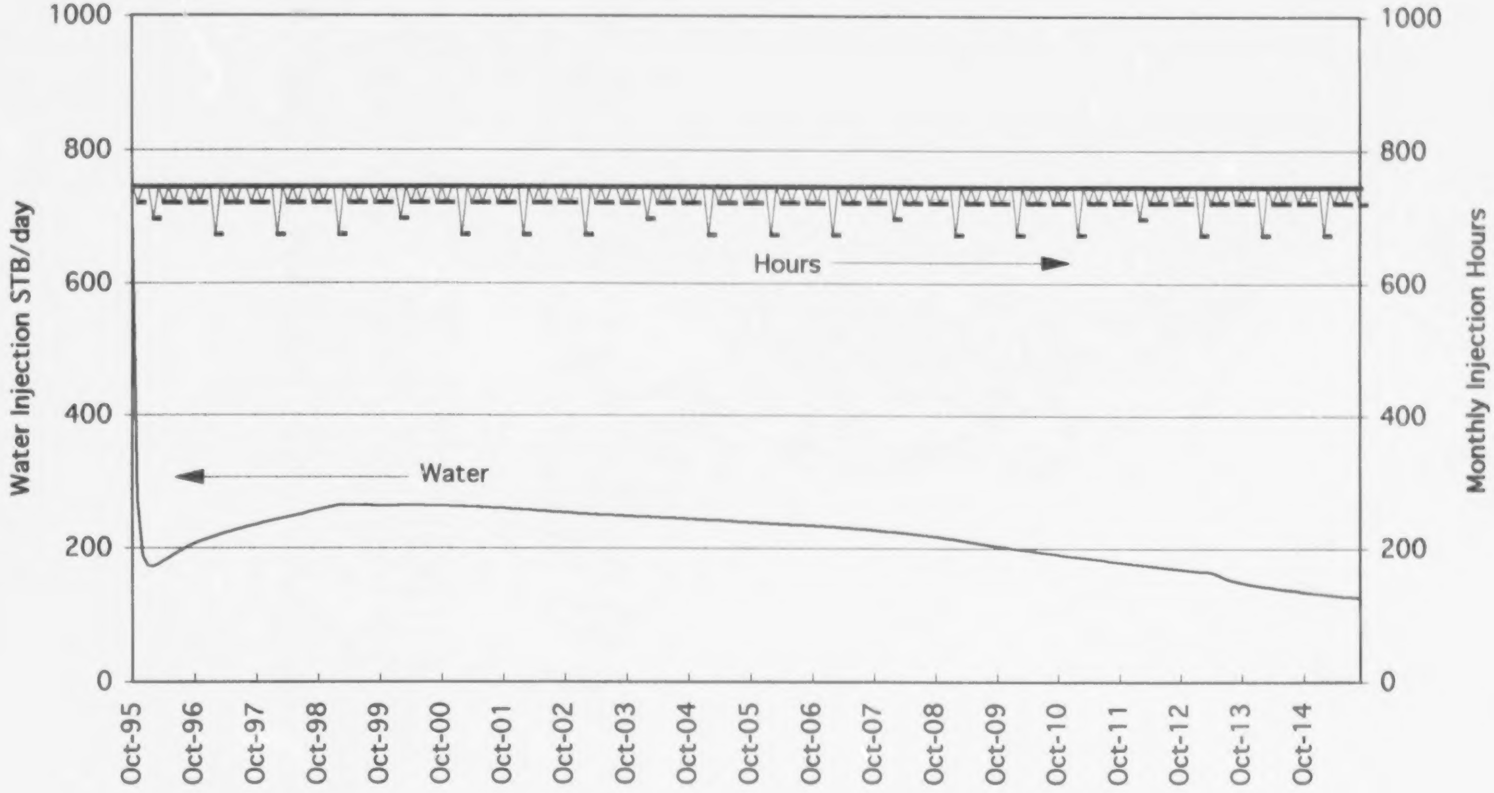

Figure 6.3(a): Waterflood Injection Forecast (06-16-37-7W5)

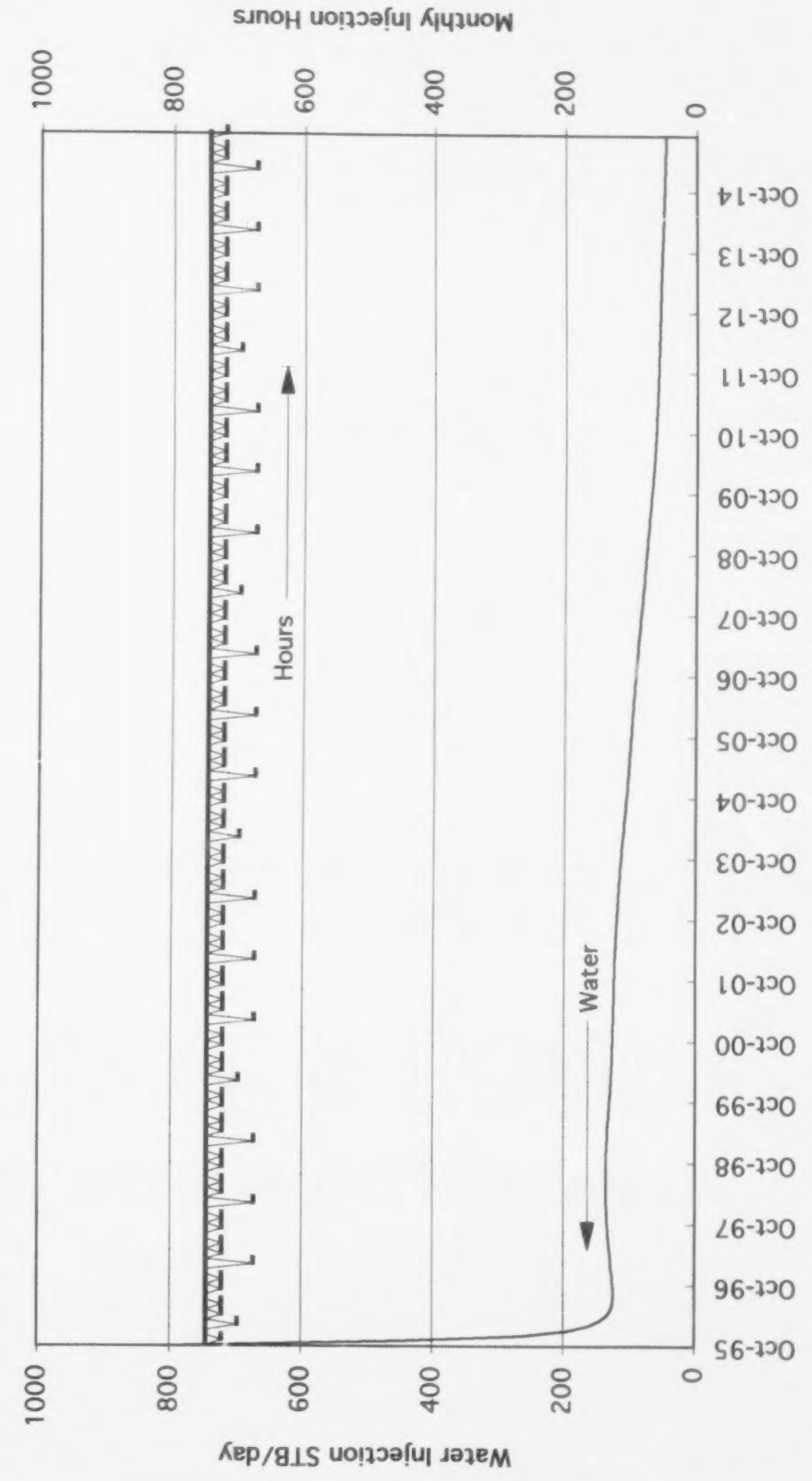

Figure 6.3(b): Waterflood Injection Forecast (16-08-37-7W5)

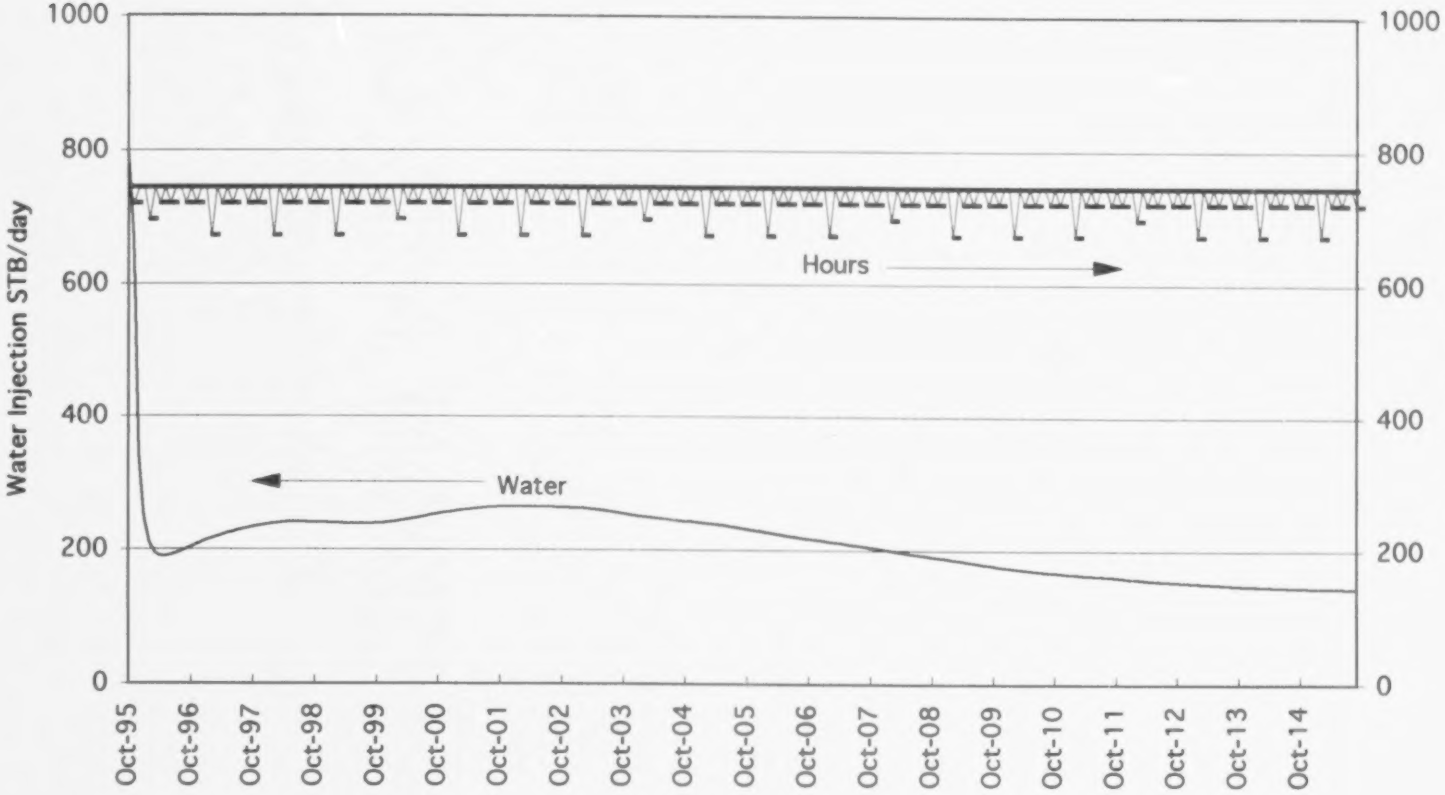

Figure 6.3(c): Waterflood Injection Forecast (10-7-37-7W5)

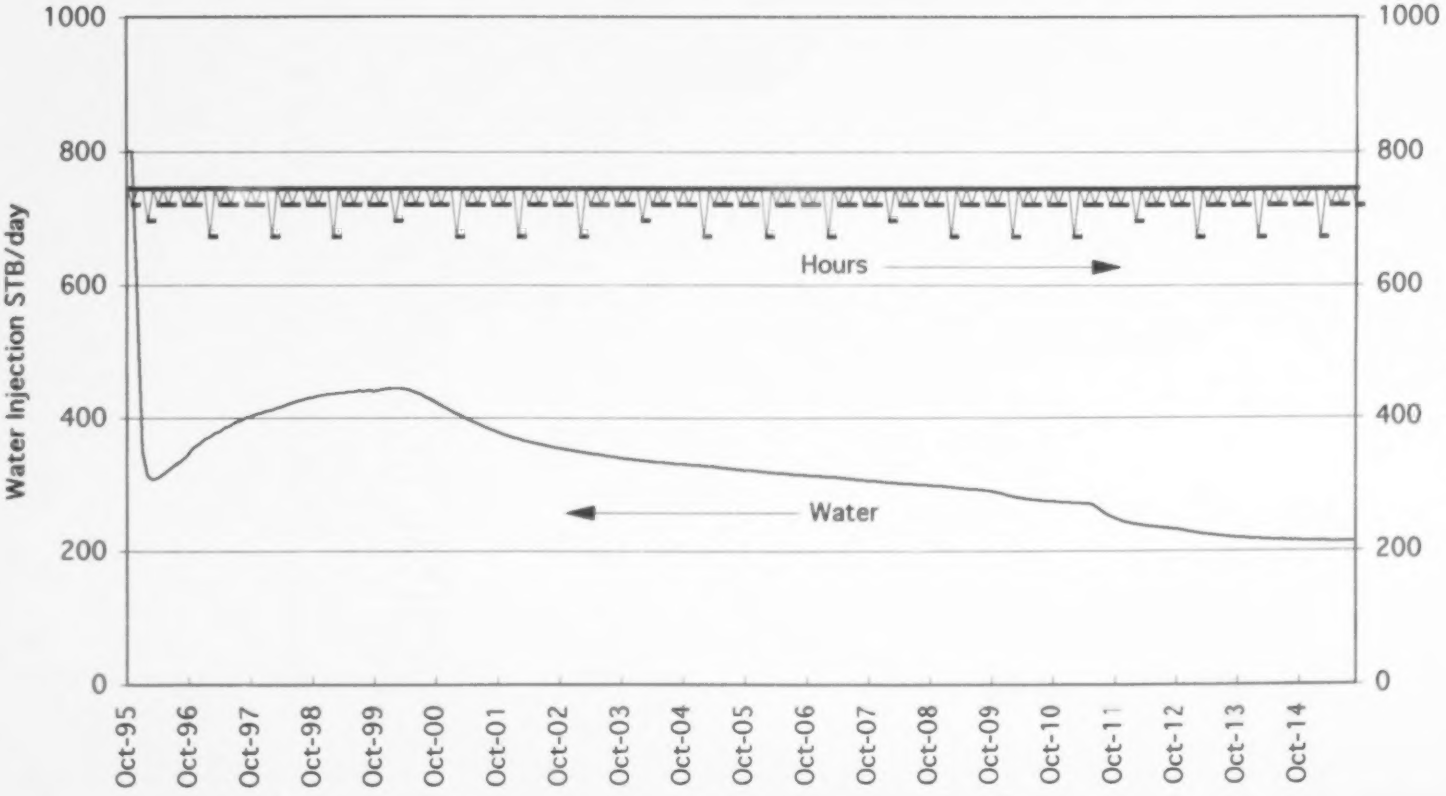

Figure 6.3(d): Waterflood Injection Forecast (12-07-37-7W5)

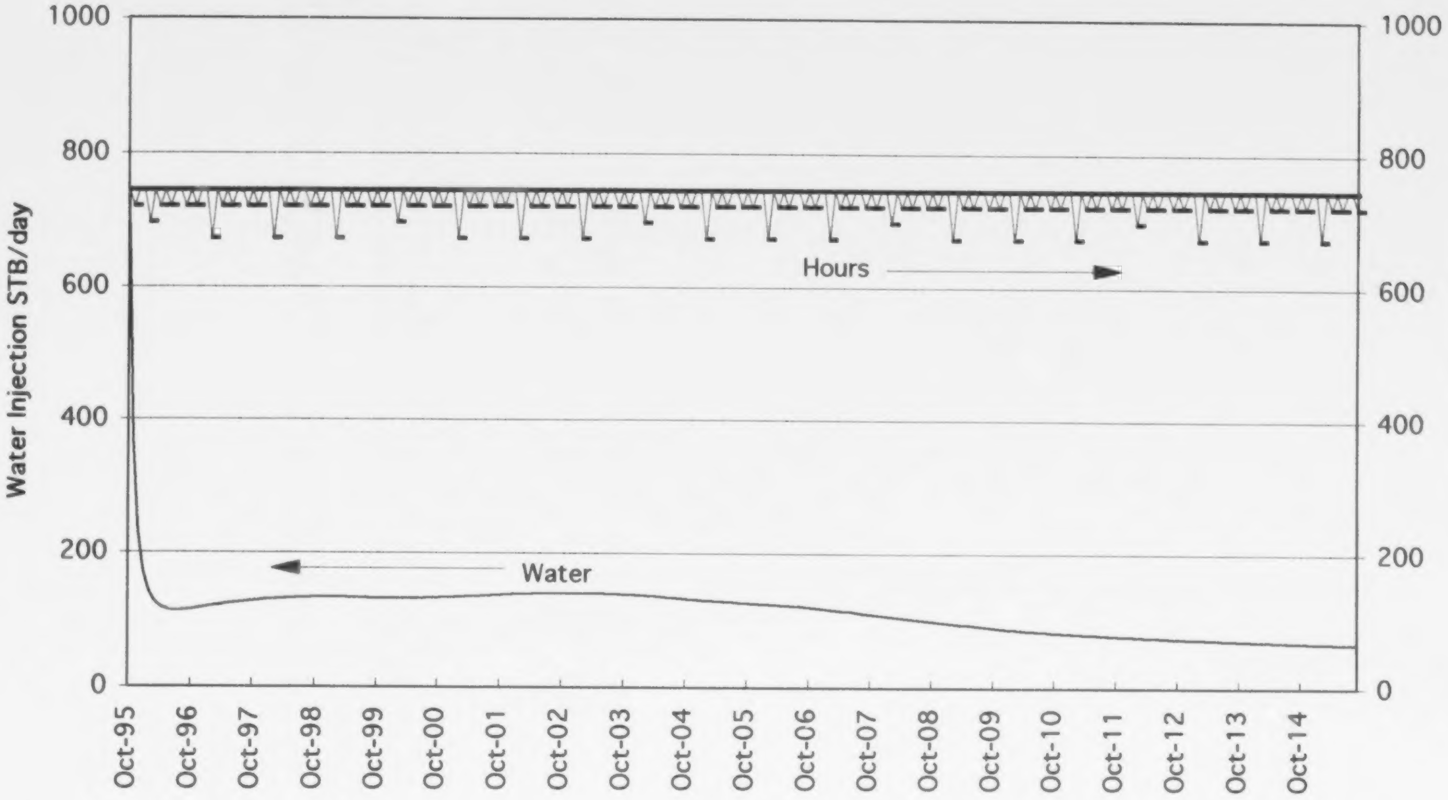

Figure 6.3(e): Waterflood Injection Forecast (10-08-37-7W5)

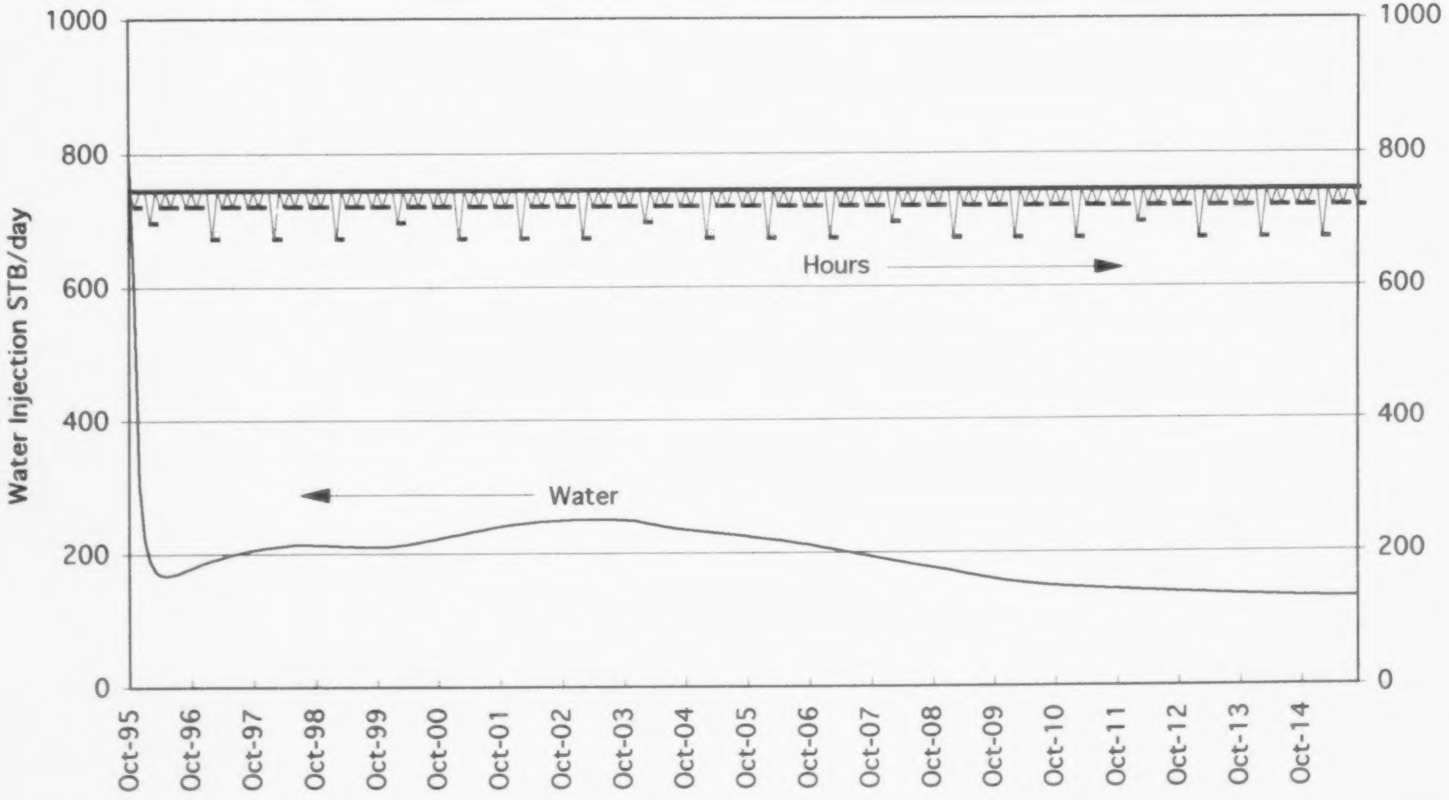

Figure 6.3(f): Waterflood Injection Forecast (12-08-37-7W5)

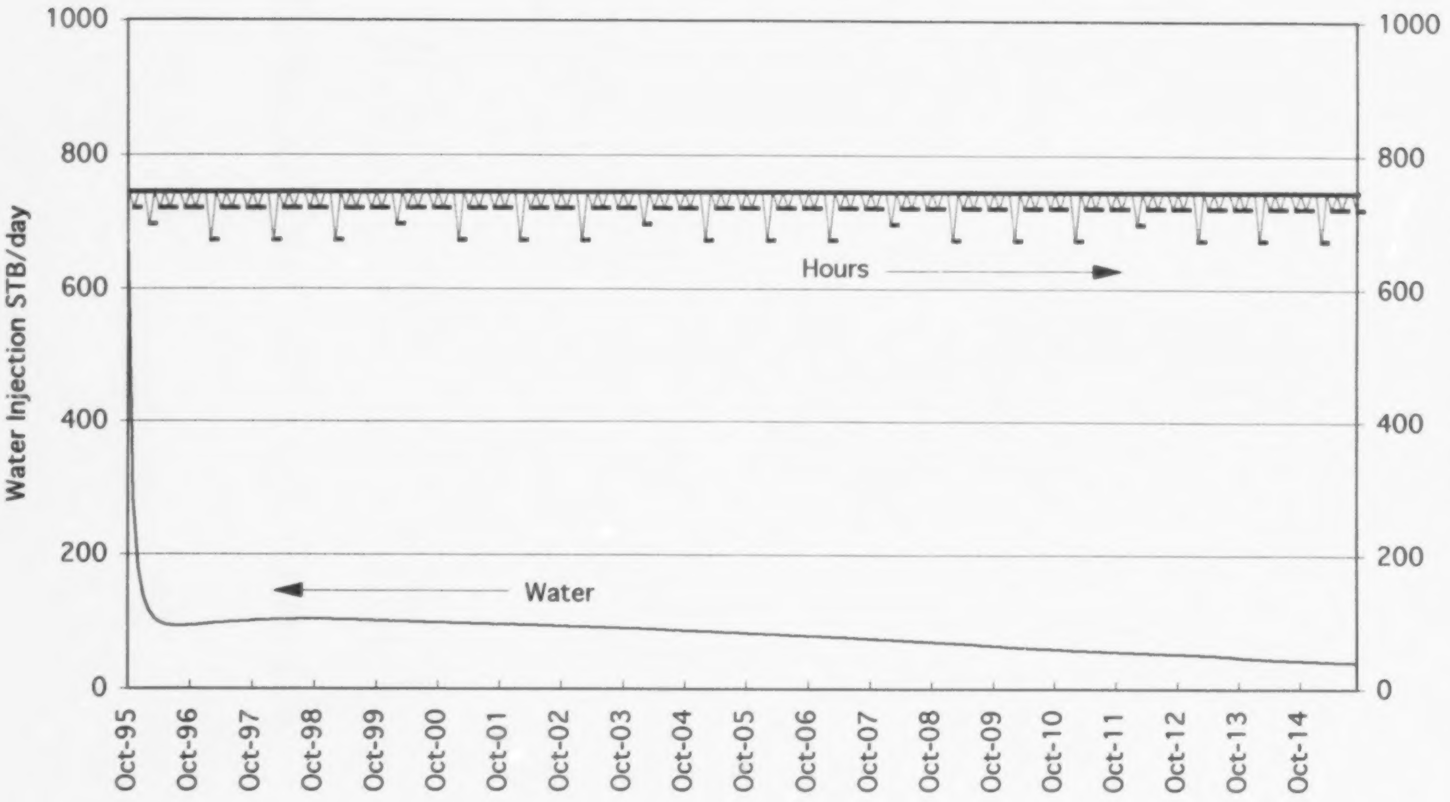

Figure 6.3(g): Waterflood Injection Forecast (04-16-37-7W5)

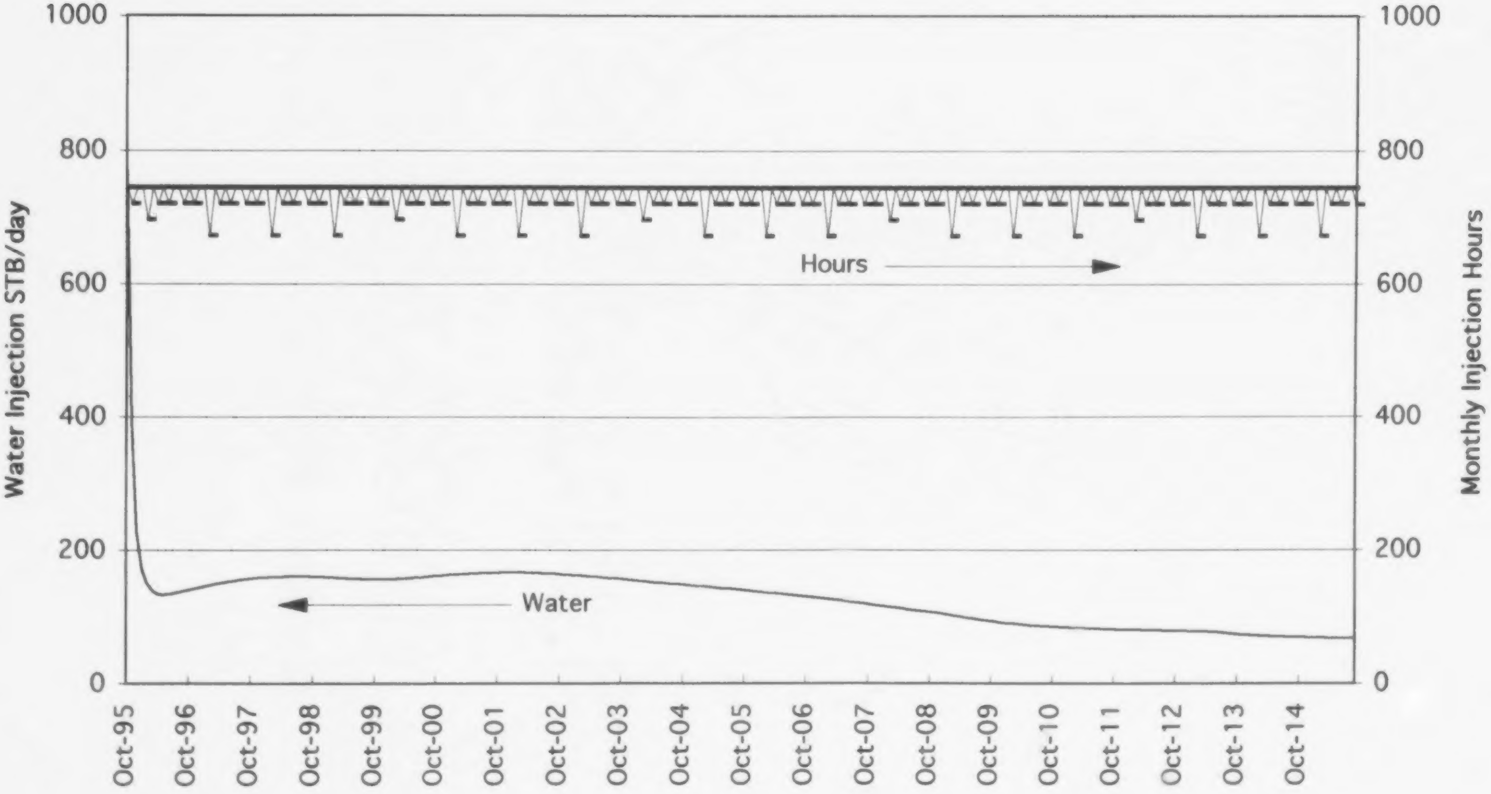

Figure 6.3(h): Waterflood Injection Forecast (02-17-37-7W5)

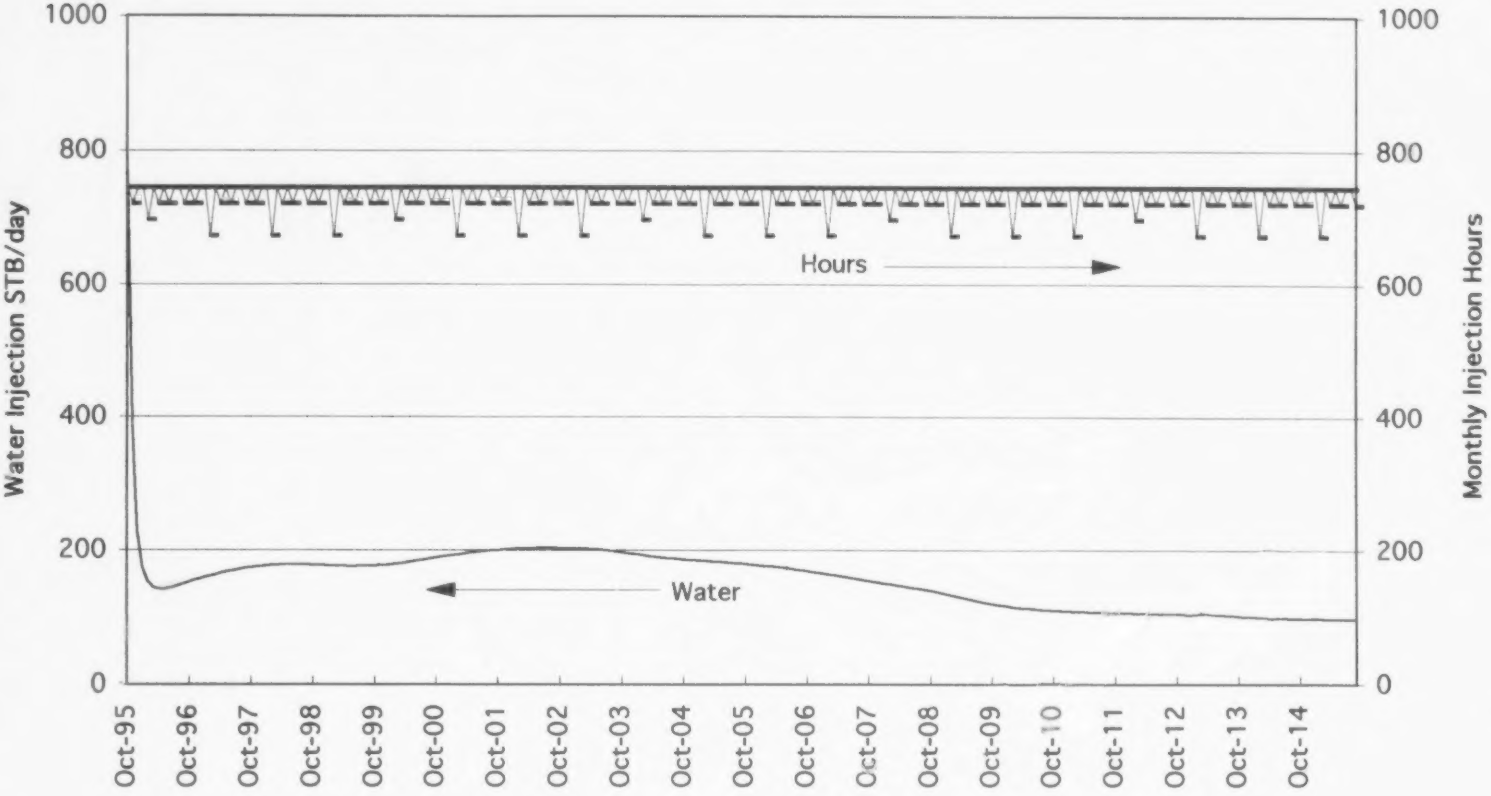

Figure 6.3(i): Waterflood Injection Forecast (04-17-37-7W5)

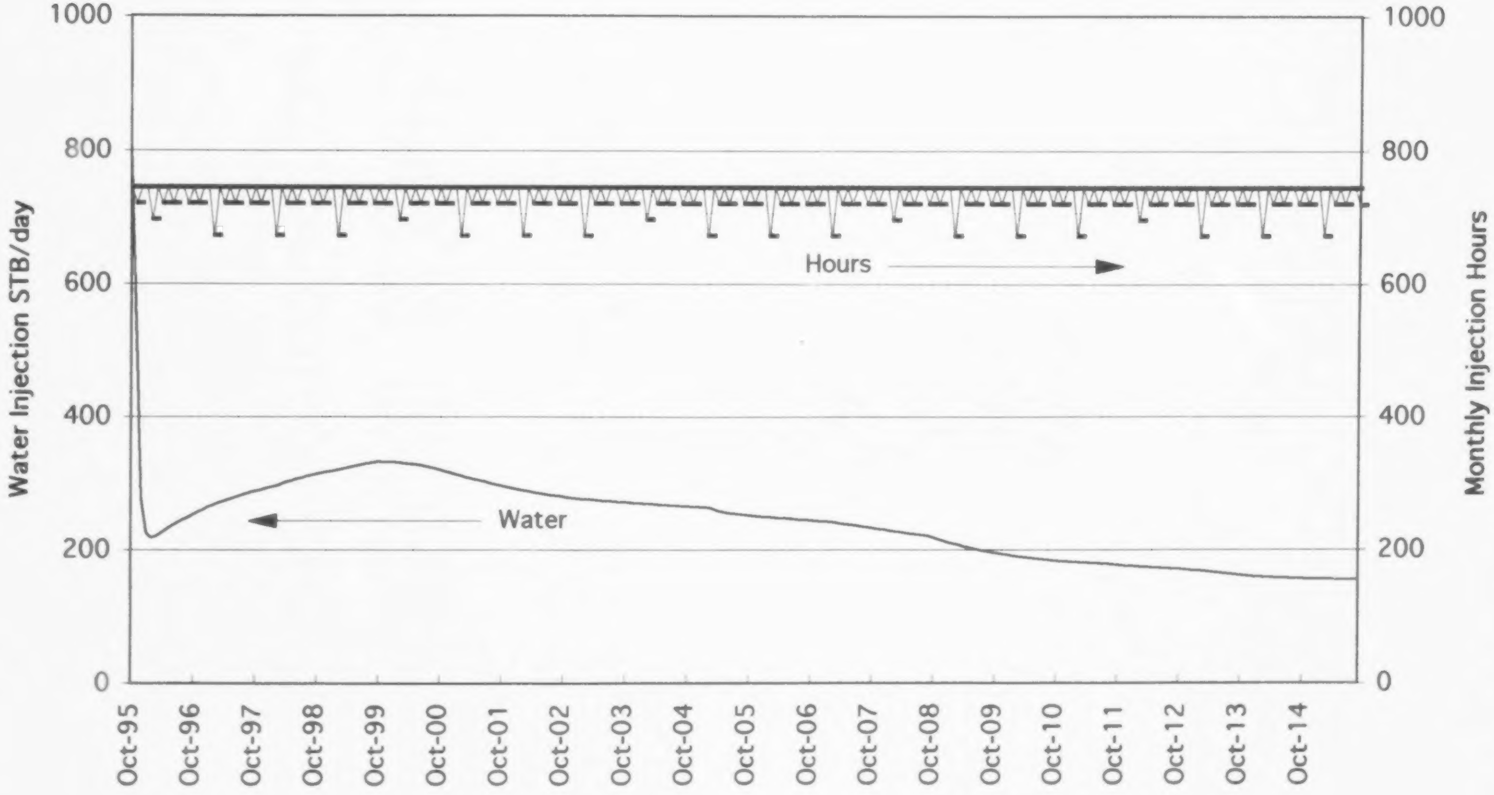

Figure 6.3(j): Waterflood Injection Forecast (02-18-37-7W5)

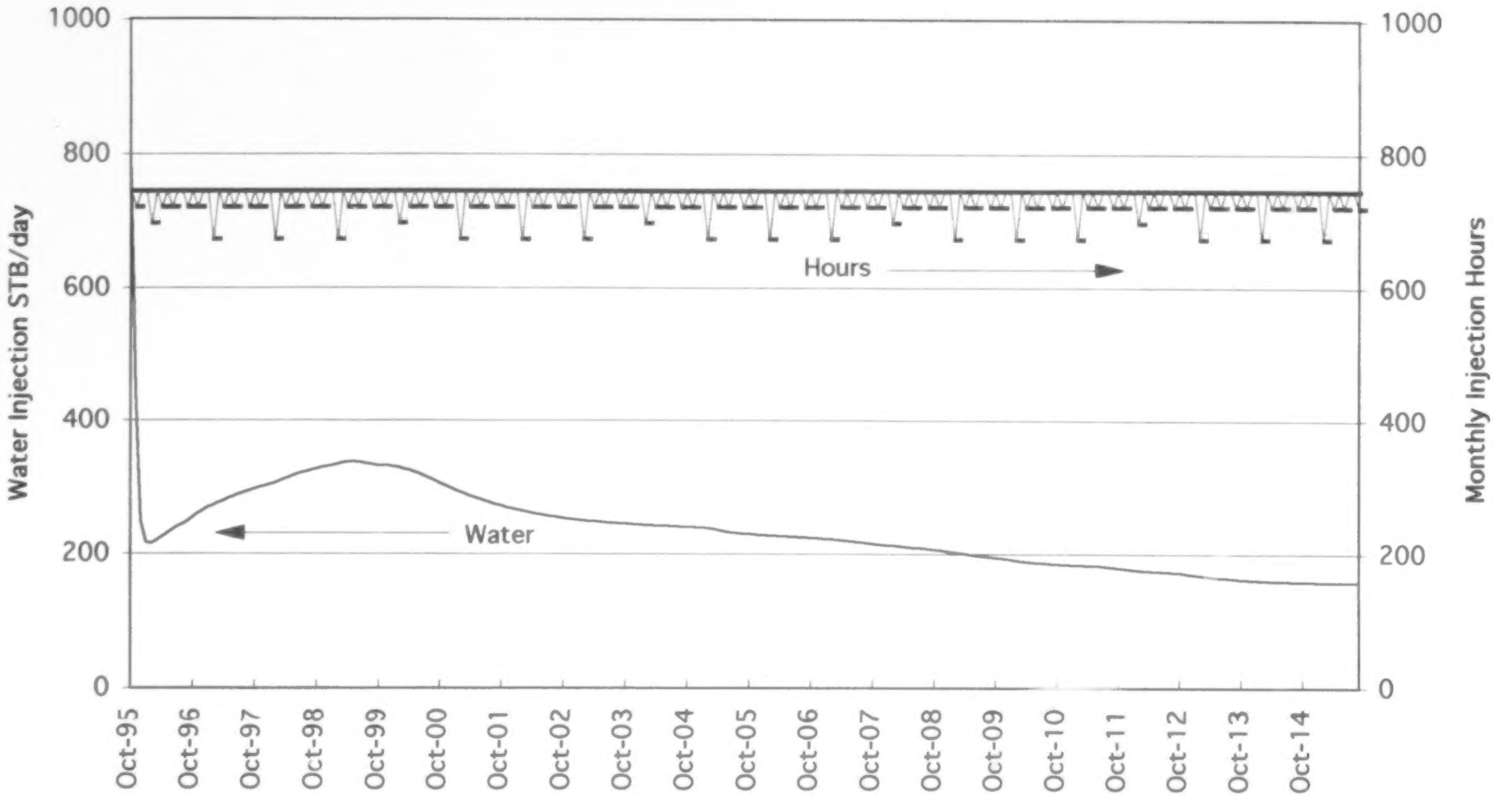

Figure 6.3(k): Waterflood Injection Forecast (04-18-37-7W5)

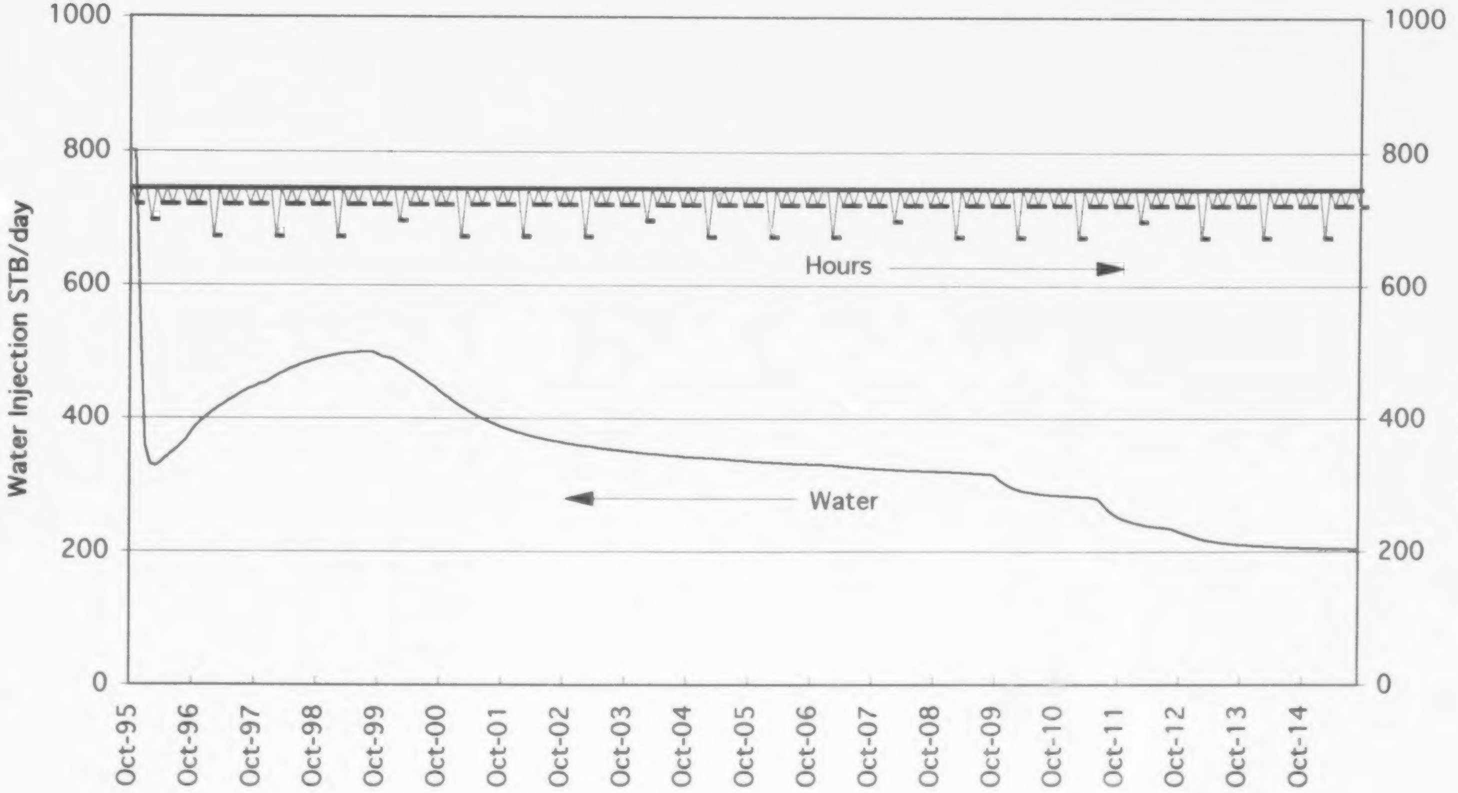

Figure 6.3(I): Waterflood Injection Forecast (10-12-37-8W5)

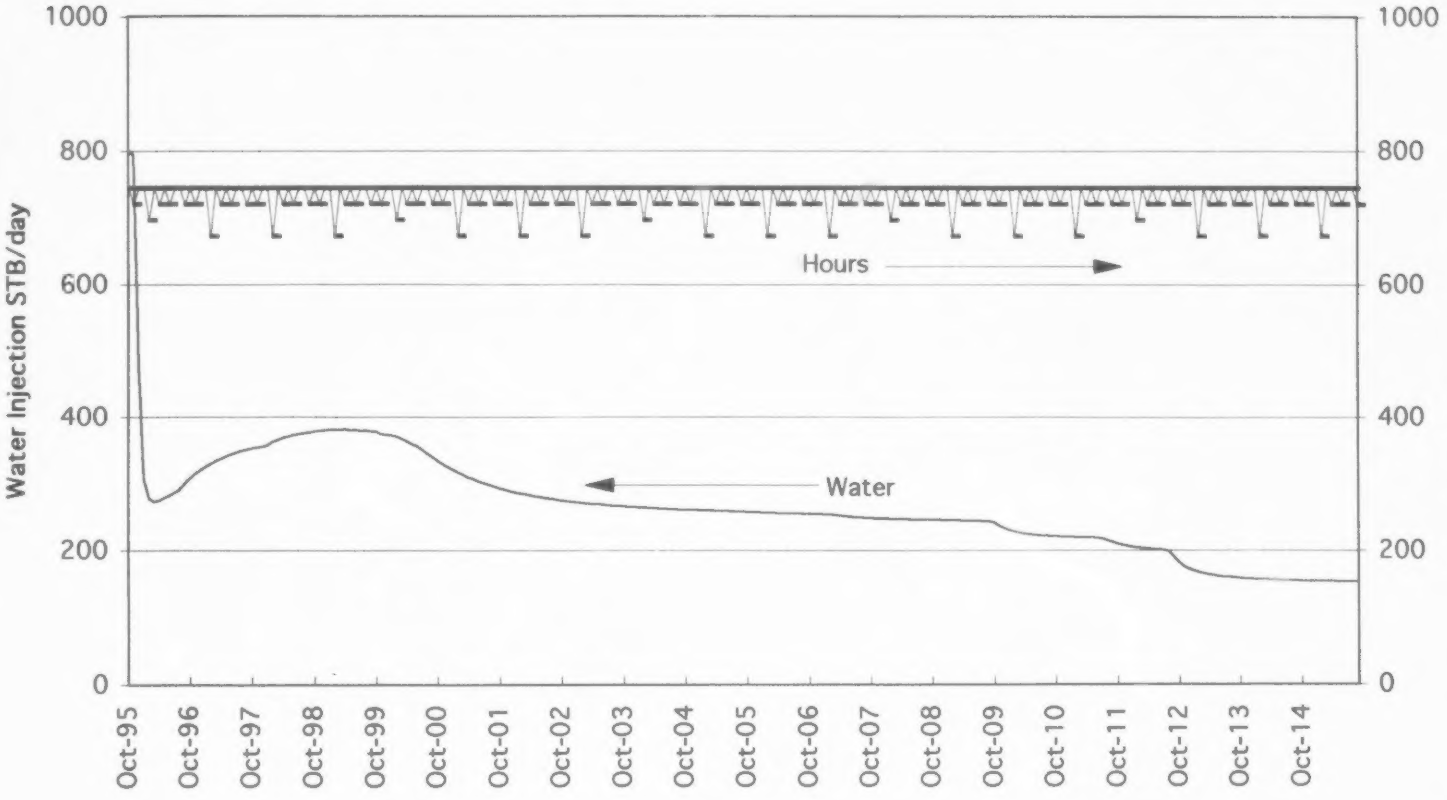

Figure 6.3(m): Waterflood Injection Forecast (12-12-37-8W5)

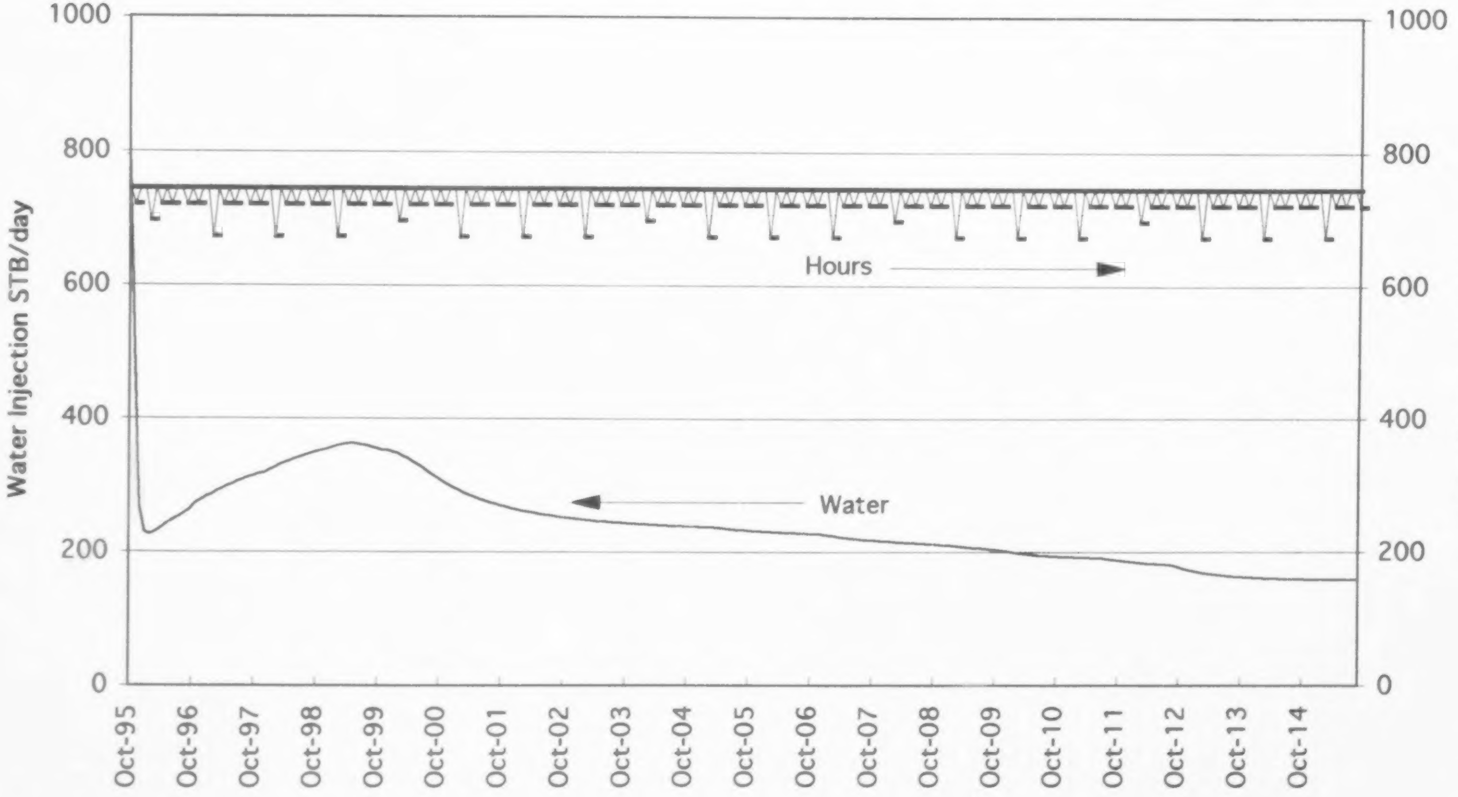

Figure 6.3(n): Waterflood Injection Forecast (02-13-37-8W5)

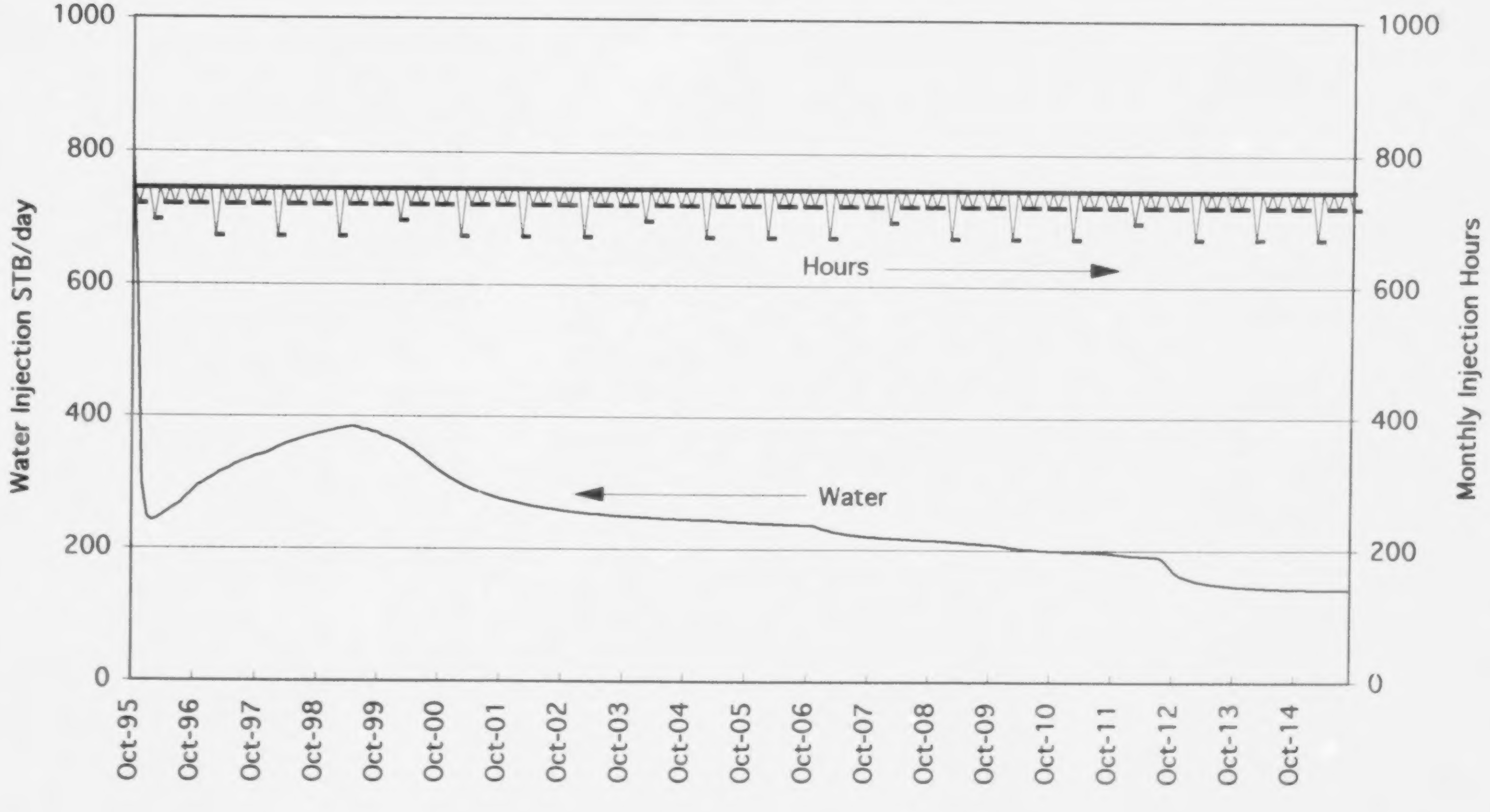

Figure 6.3(o): Waterflood Injection Forecast (04-13-37-8W5)

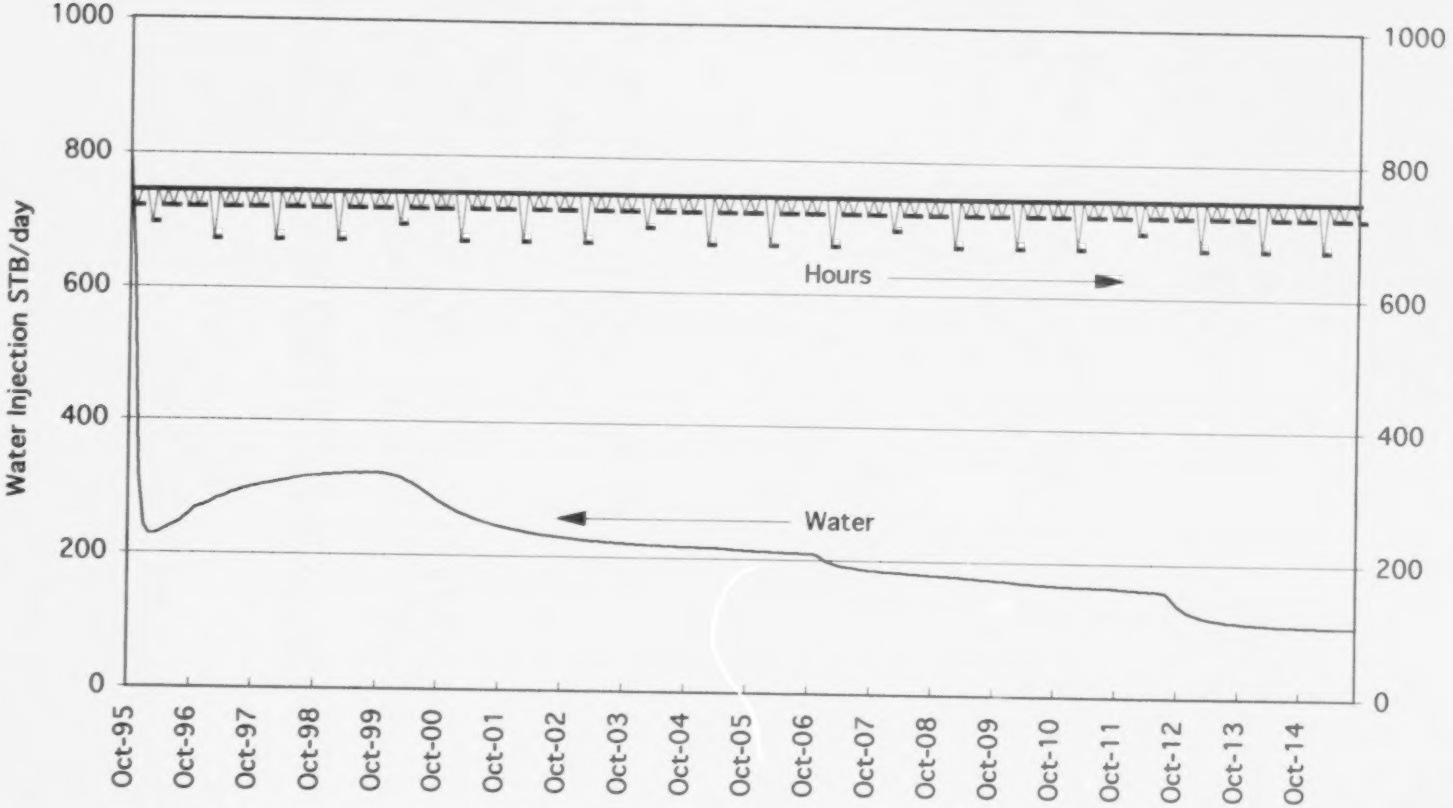

Figure 6.3(p): Waterflood Injection Forecast (02-14-37-8W5)

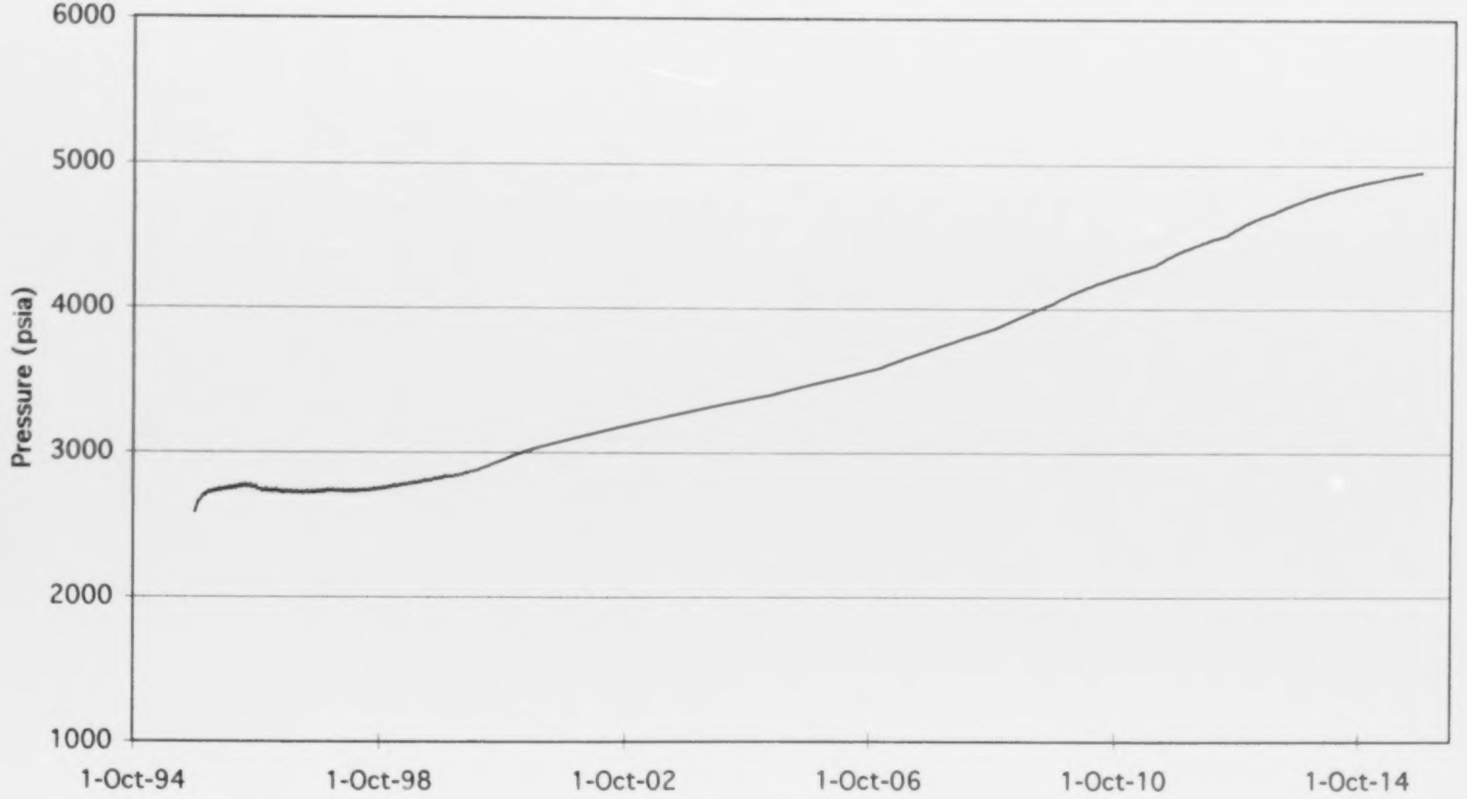

Figure 6.4(a): Waterflood Average Reservoir Pressure Prediction

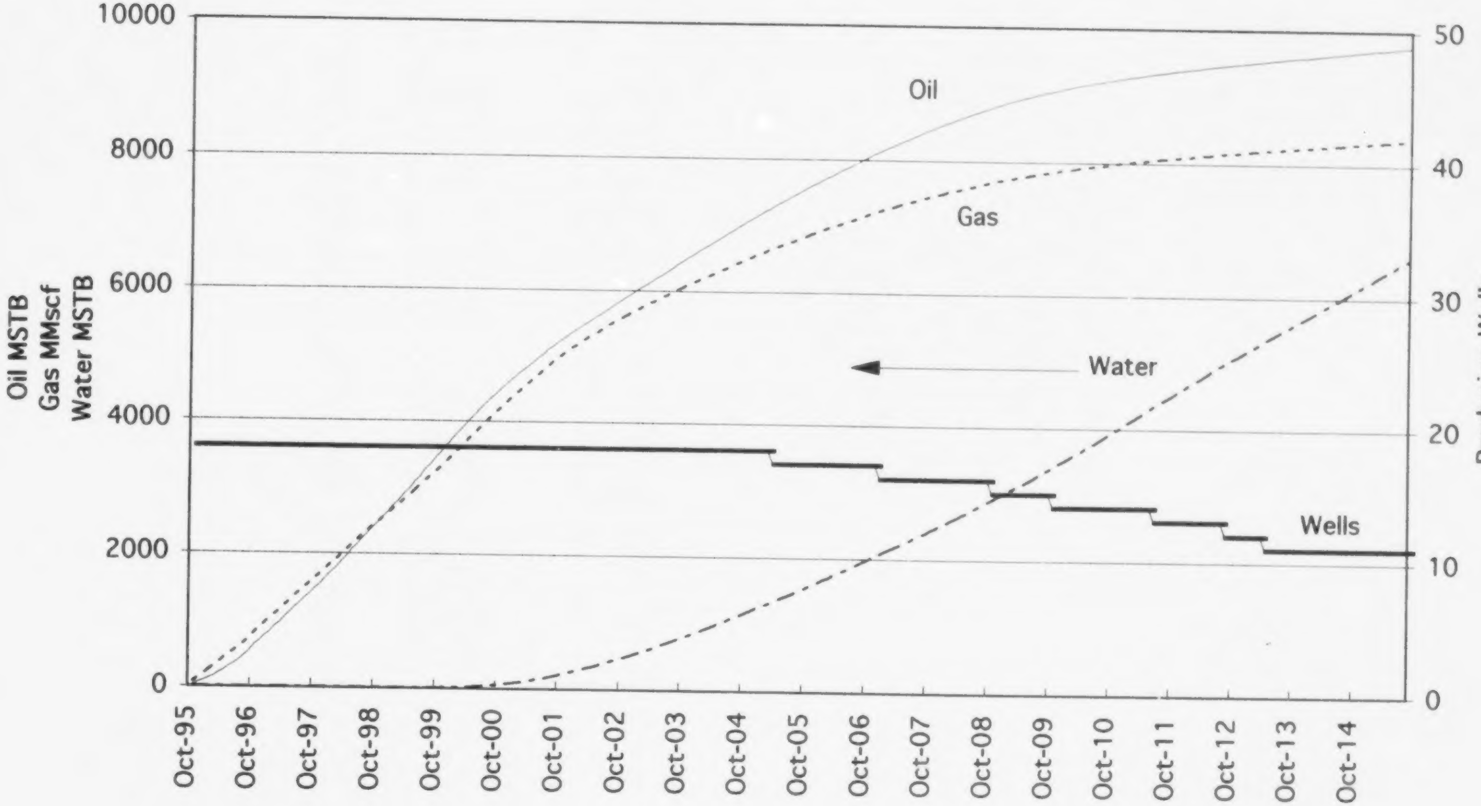

Figure 6.4(b): Pool Cumulative Waterflood Production Forecast

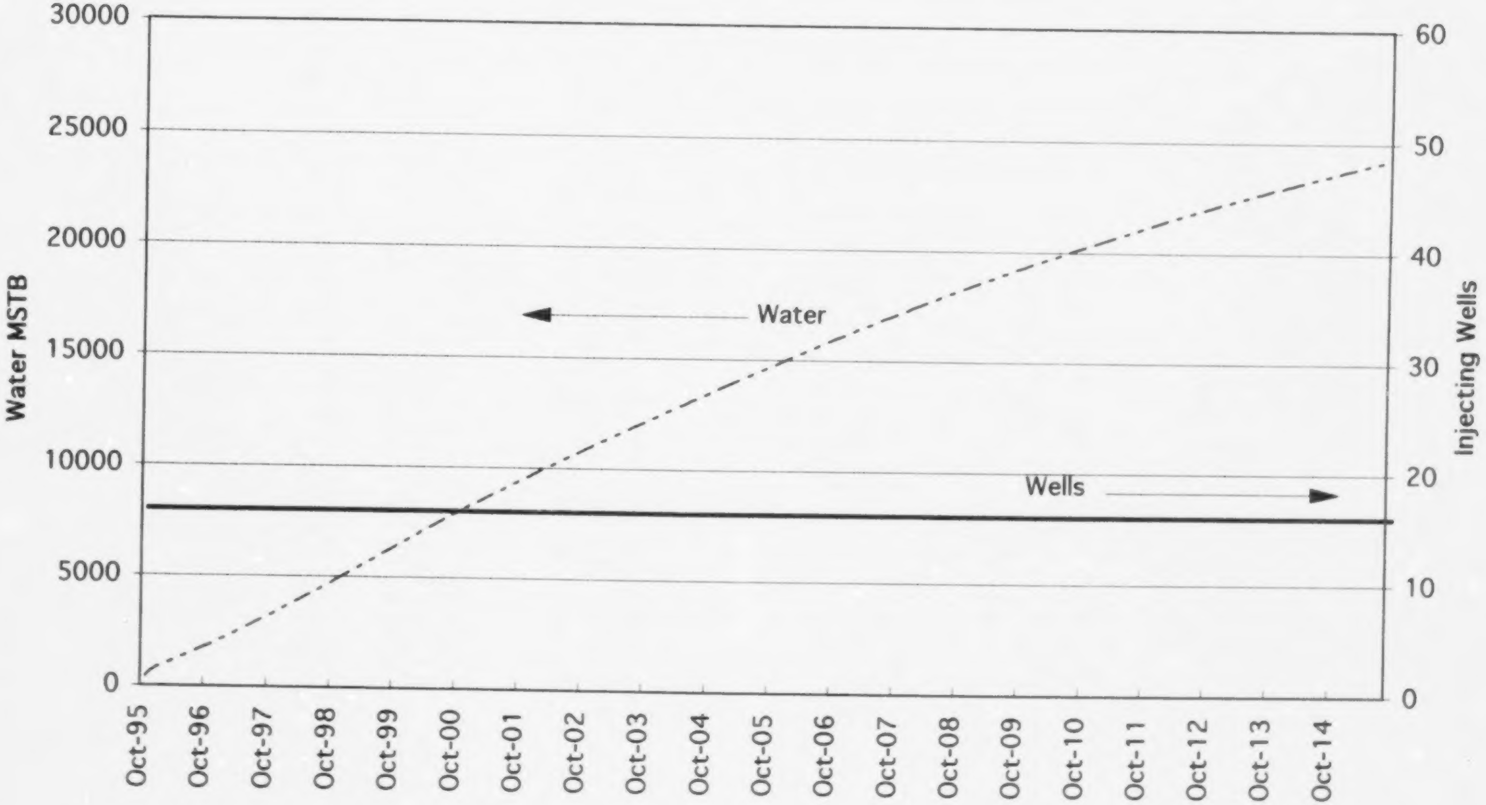

Figure 6.4(c): Pool Cumulative Waterflood Injection Forecast

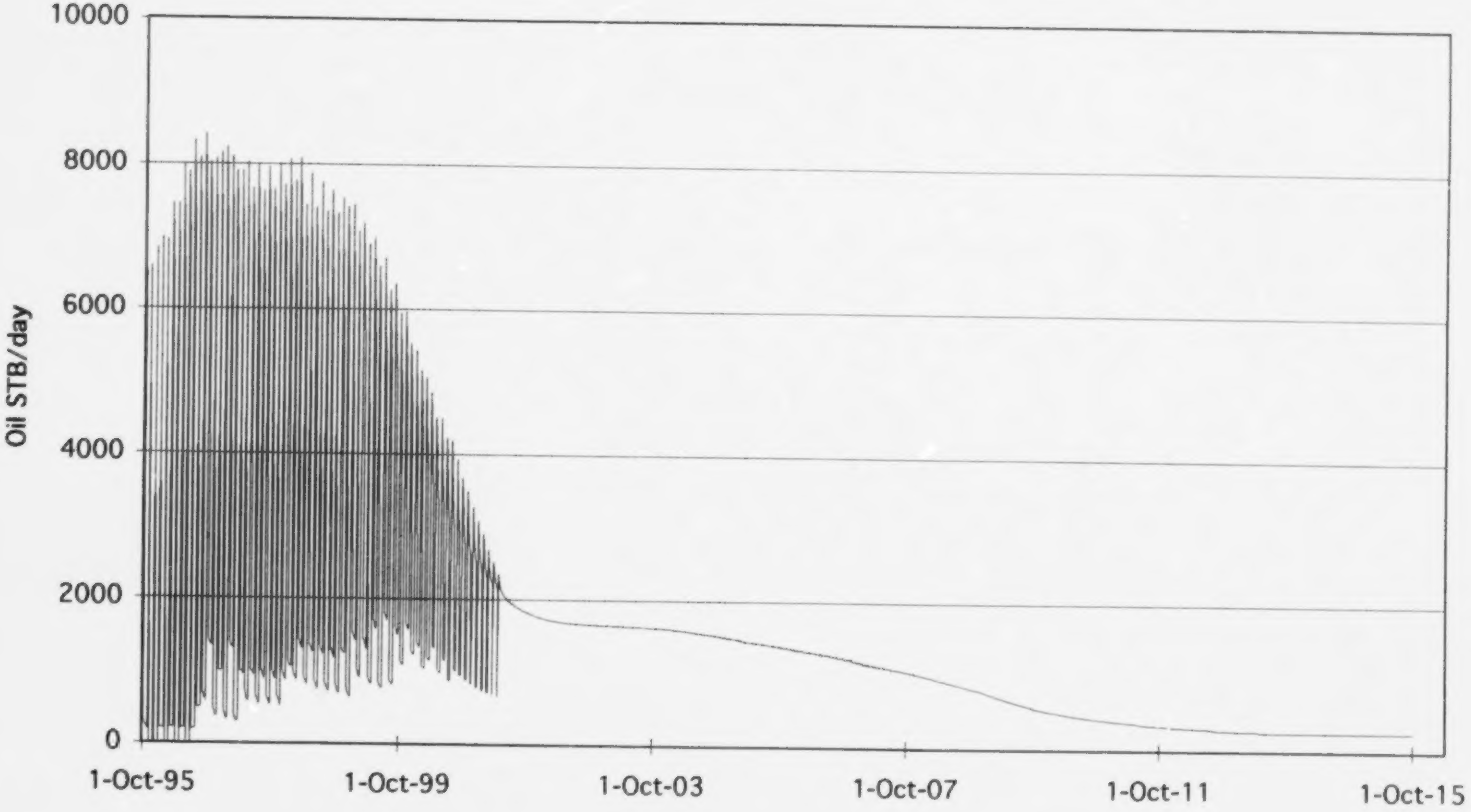

Figure 6.5(a): Pool Waterflood Oil Production Rate Forecast

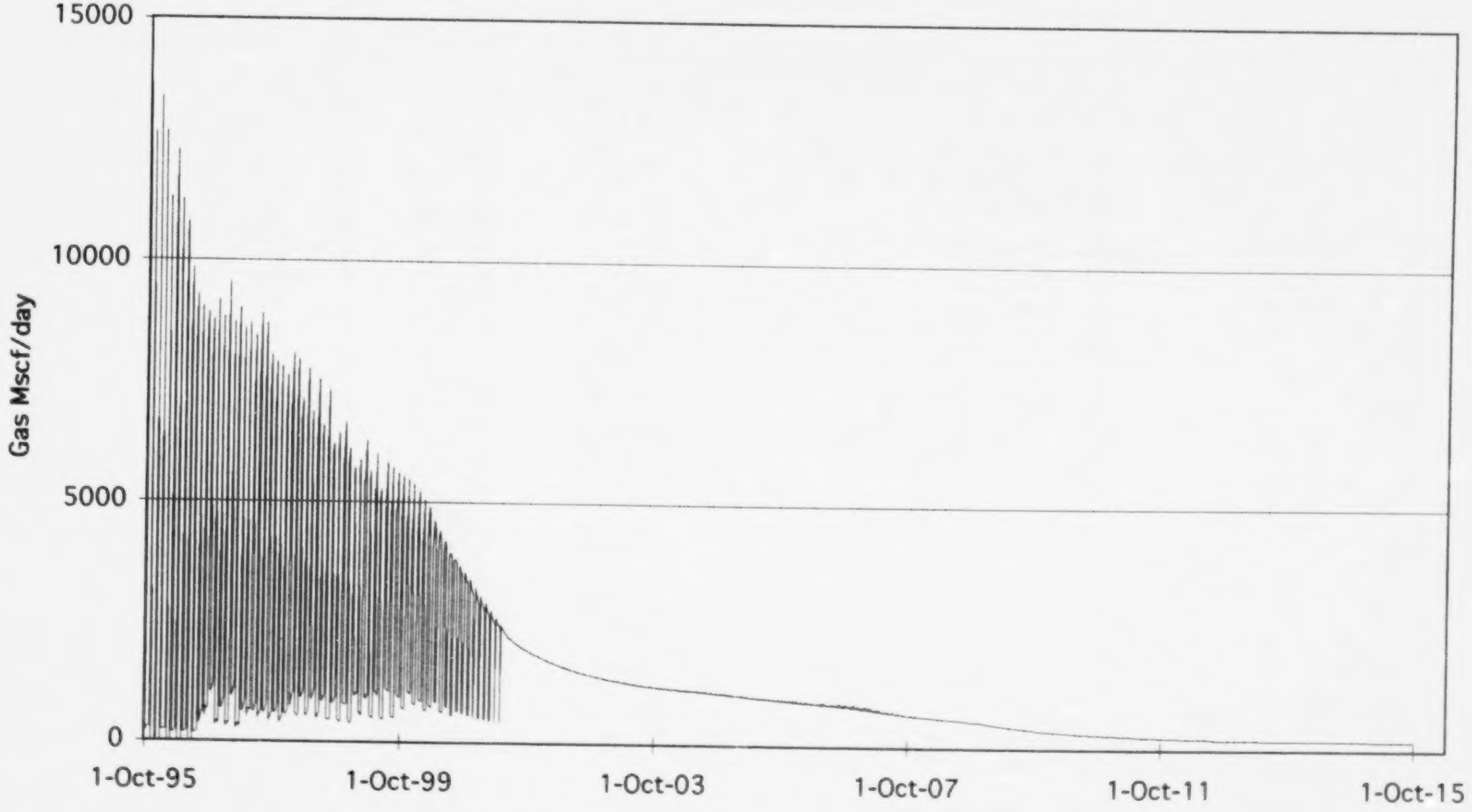

Figure 6.5(b): Pool Waterflood Gas Production Rate Forecast

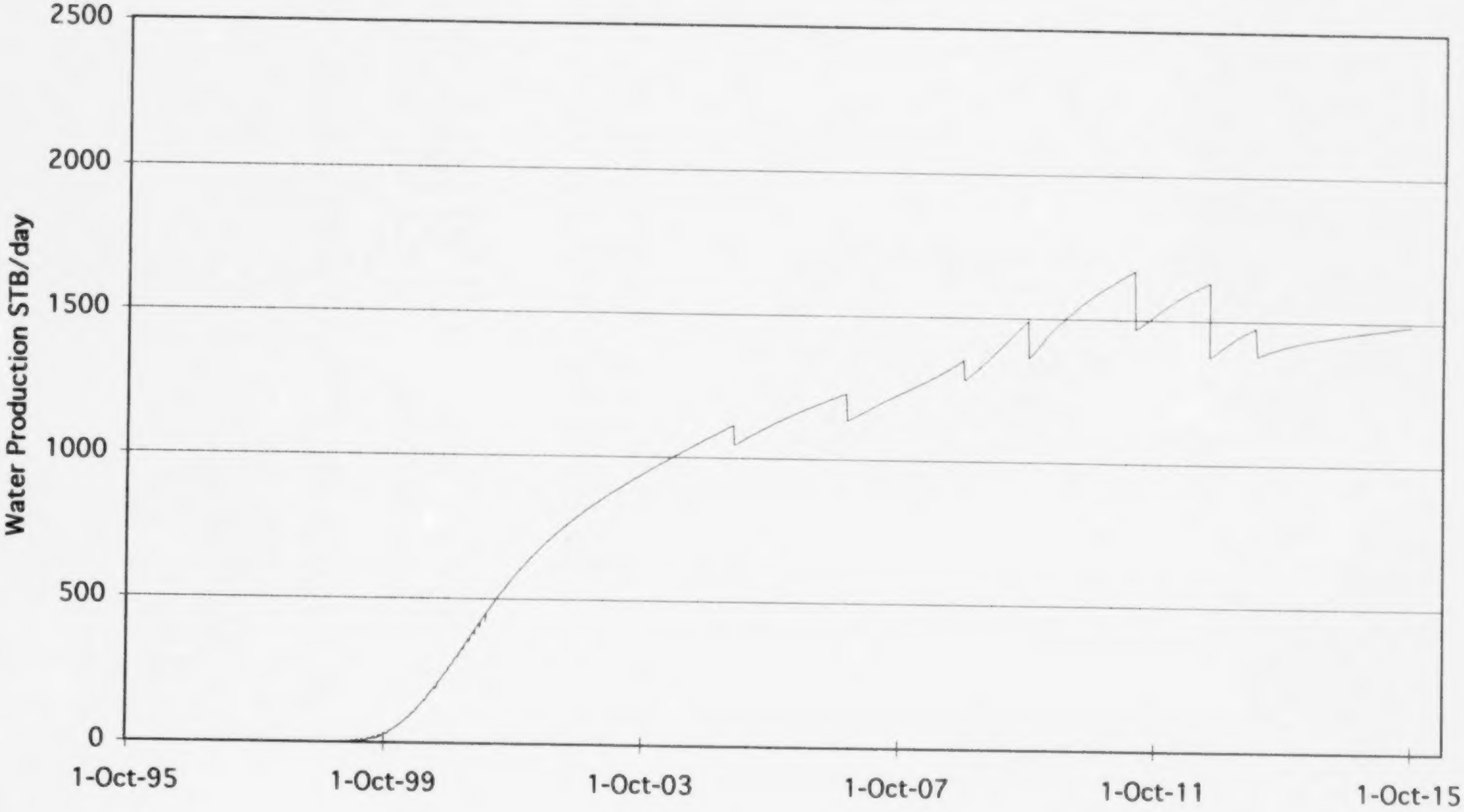

Figure 6.5(c): Pool Waterflood Water Production Rate Forecast

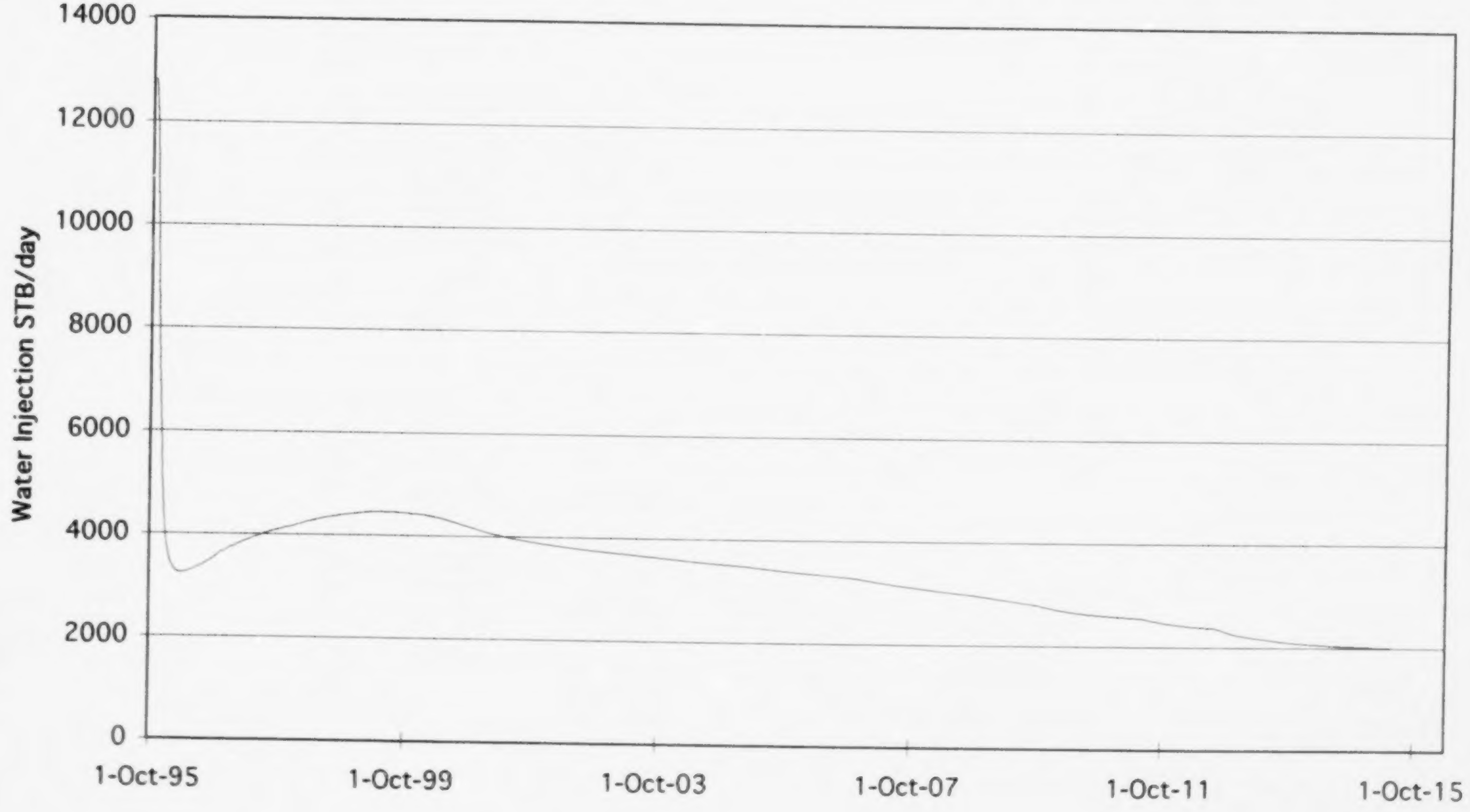

Figure 6.5(d): Pool Waterflood Water Injection Forecast

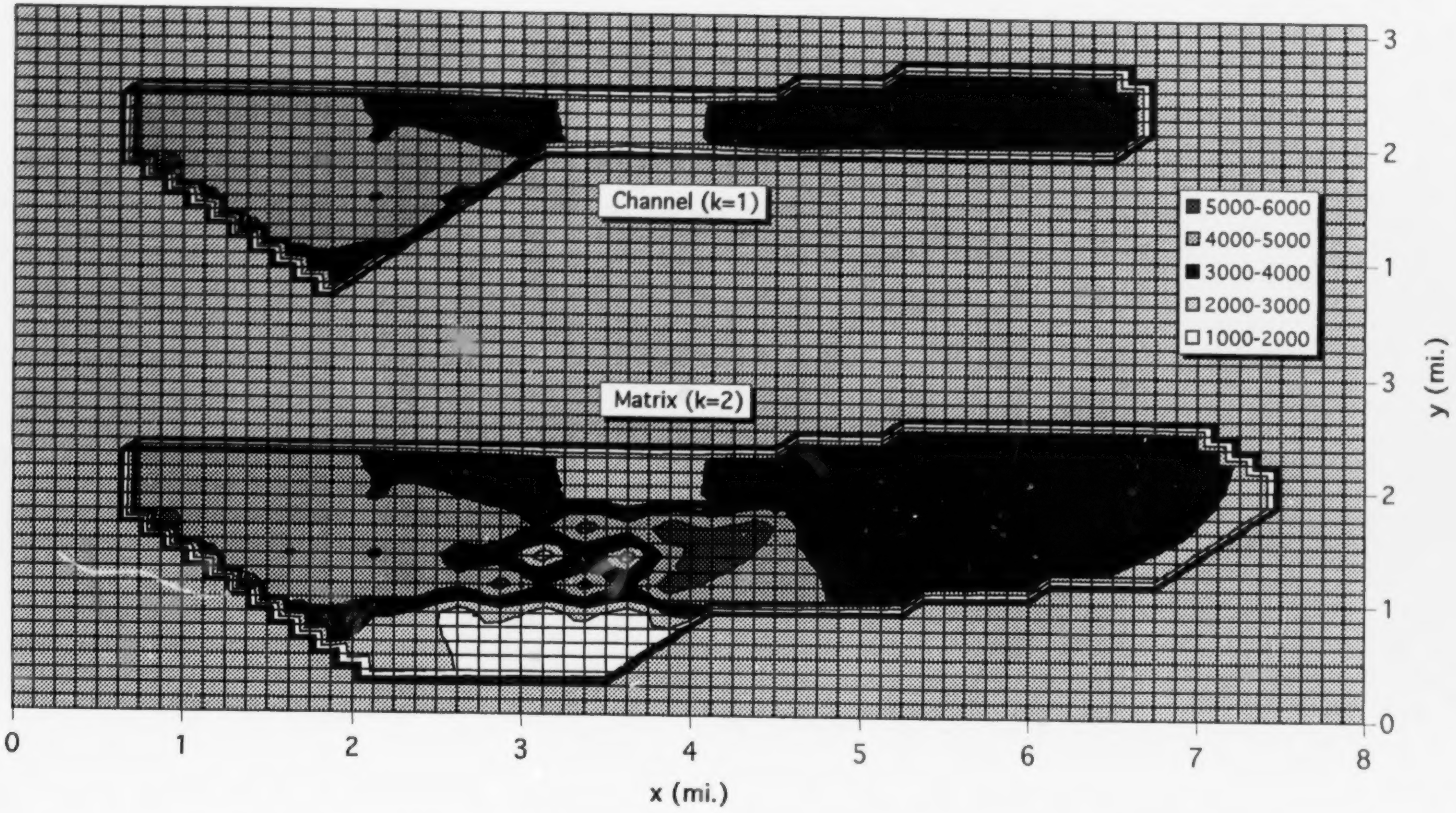

Figure 6.6(a): Waterflood (Oct-07) Pressure p (psia)

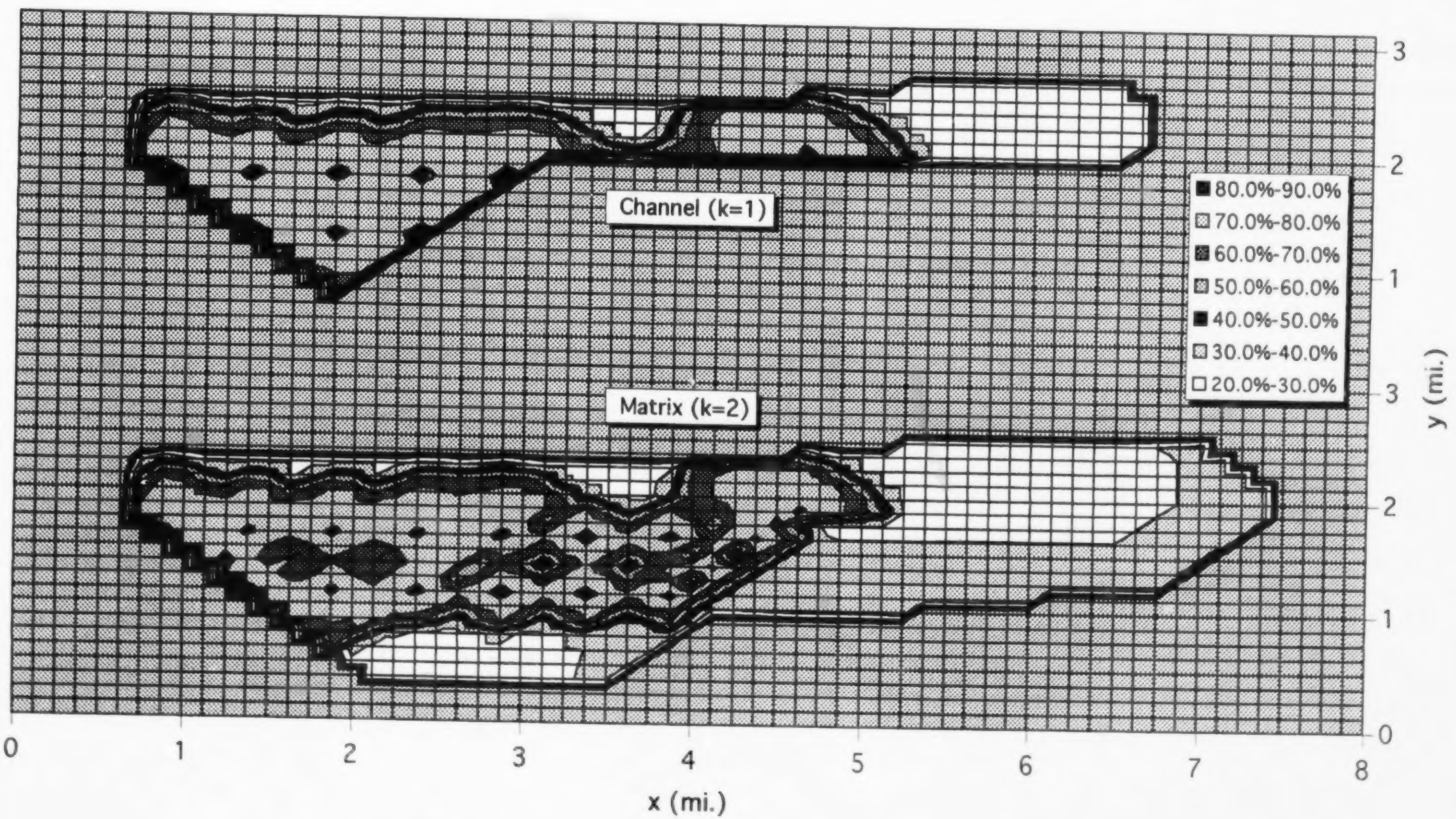

Figure 6.6(b): Waterflood (Oct-07) Water Saturation S_w

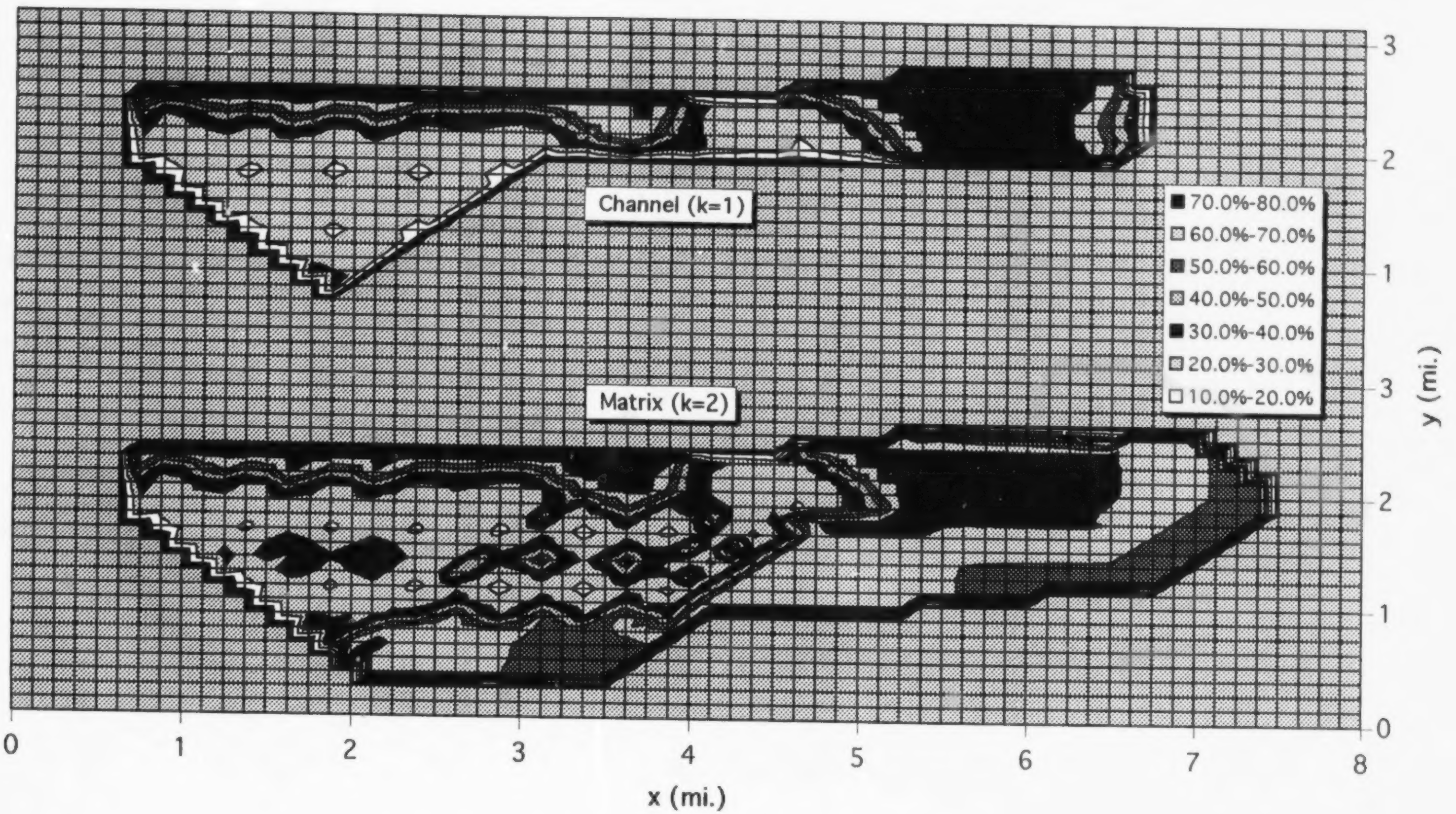

Figure 6.6(c): Waterflood (Oct-07) Oil Saturation S_o

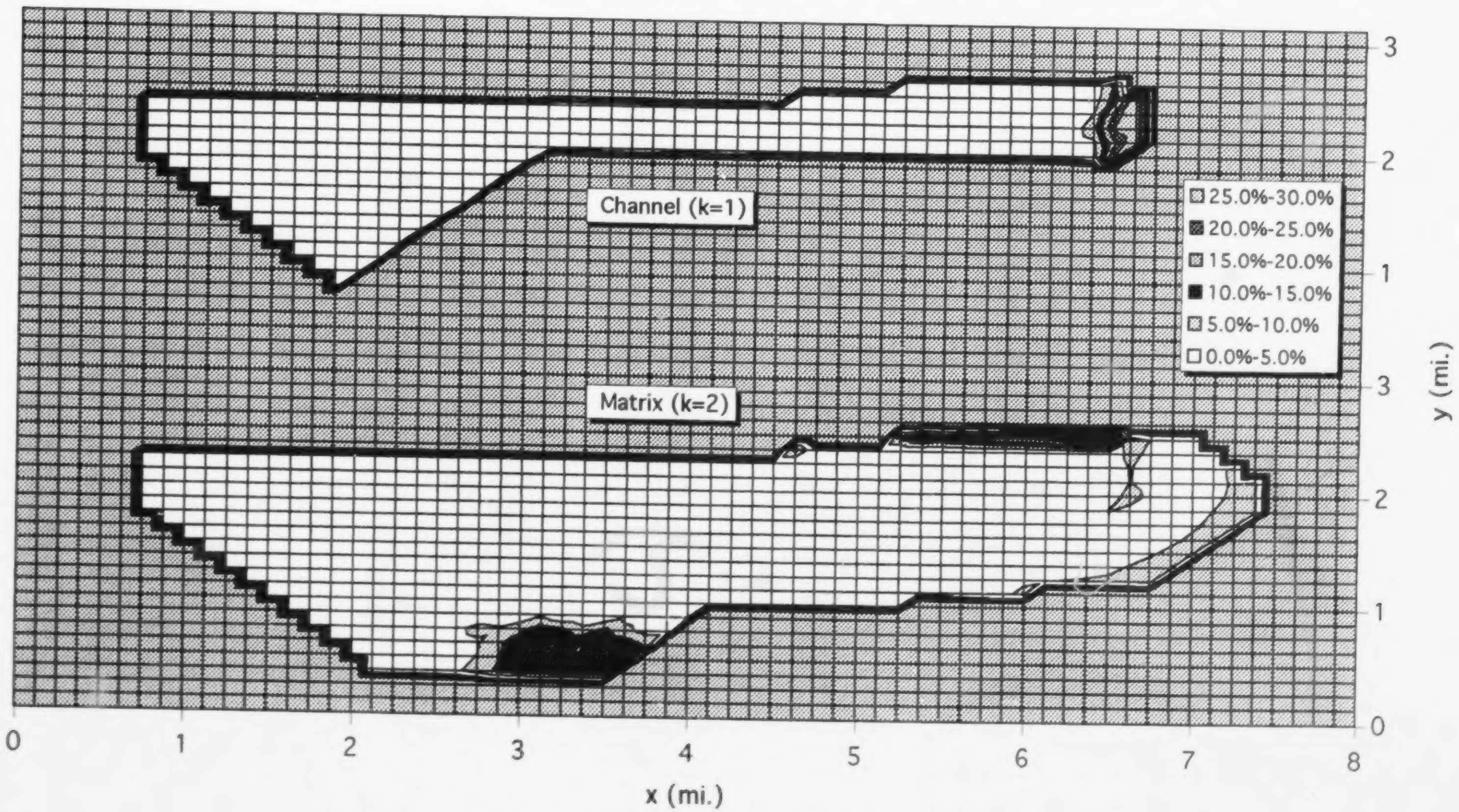

Figure 6.6(d): Waterflood (Oct-07) Gas Saturation S_g

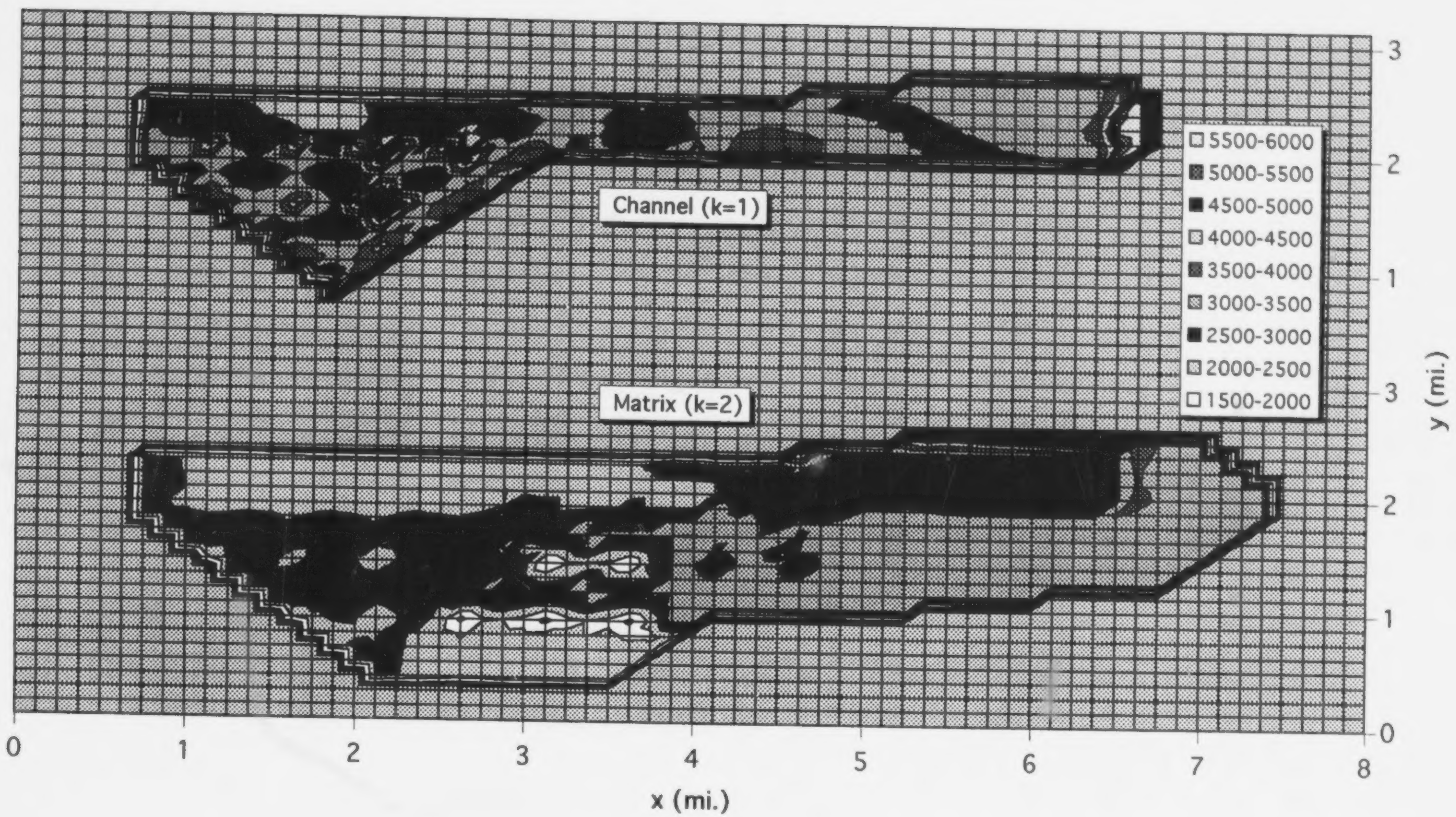

Figure 6.6(e): Waterflood (Oct-07) Bubble Point p_b (psia)

Chapter 7: Reservoir Depletion Paths

7.1 Path-Dependent Production Trees

Production forecasts for secondary recovery will depend on the originating reservoir state of primary operations and the control policy (Figure 7.1). Discrete timing response is represented by production branches on a forecast tree.

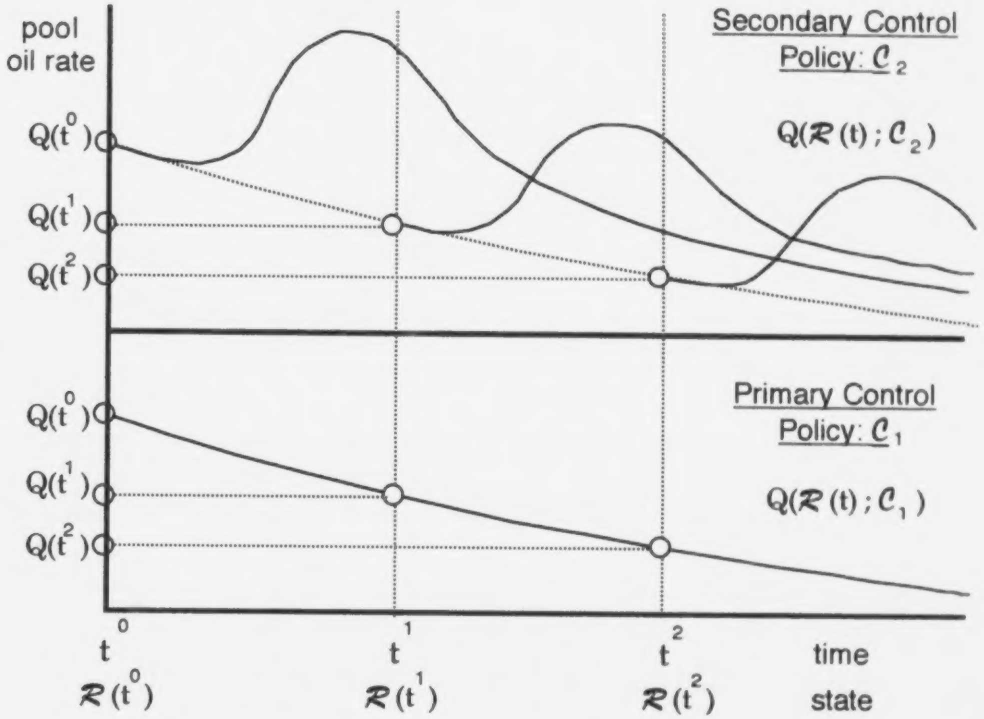
pool
oil rate
Secondary Control
Policy: $\mathcal{C}_2$
$Q(\mathcal{R}(t);\mathcal{C}_2)$
$Q(t^0)$
$Q(t^1)$
$Q(t^2)$
Primary Control
Policy: $\mathcal{C}_1$
$Q(\mathcal{R}(t);\mathcal{C}_1)$
$Q(t^0)$
$Q(t^1)$
$Q(t^2)$
t^0
$\mathcal{R}(t^0)$
t^1
$\mathcal{R}(t^1)$
t^2
$\mathcal{R}(t^2)$
time
state

Figure 7.1: Path Dependence of Production Forecast

Project evaluation will be based on cash flow projections for the entire pool. Operating and investment timing decisions will choose between mutually exclusive production alternatives. Cash flows will depend on the contemporaneous pooled production rate Q(t).

$$Q(t) = \sum_{\text{Producers}} Q(t) \tag{7.1}$$

The pooled oil production rate $Q_o(t)$ will depend on the reservoir state $\mathcal{R}(t)$ and the control policy $\mathcal{C}$. The reservoir state $\mathcal{R}(t)$ is determined by the state variables (p, S_w, S_g) which are distributed in both space and time. The active control policy will depend on the reservoir state and the recovery stage: $\mathcal{C}_1$ for primary control and $\mathcal{C}_2$ for secondary waterflood control. Controls will be distributed in time at particular points in the reservoir space. Continuous forecasting of path-dependent secondary recovery is virtually intractable. Consequently, decision pathways are confined to discrete secondary timing options only (Figure 7.2).

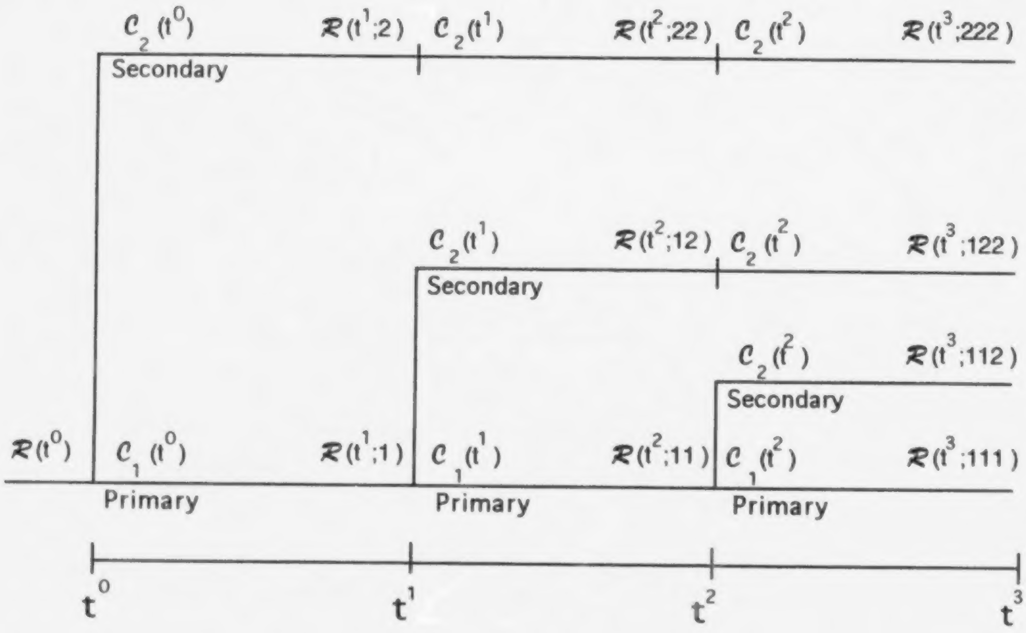
$\mathcal{C}_2(t^0)$
$\mathcal{R}(t^1;2)$
$\mathcal{C}_2(t^1)$
$\mathcal{R}(t^2;22)$
$\mathcal{C}_2(t^2)$
$\mathcal{R}(t^3;222)$
Secondary
$\mathcal{C}_2(t^1)$
$\mathcal{R}(t^2;12)$
$\mathcal{C}_2(t^2)$
$\mathcal{R}(t^3;122)$
Secondary
$\mathcal{C}_2(t^2)$
$\mathcal{R}(t^3;112)$
Secondary
$\mathcal{R}(t^0)$
$\mathcal{C}_1(t^0)$
$\mathcal{R}(t^1;1)$
$\mathcal{C}_1(t^1)$
$\mathcal{R}(t^2;11)$
$\mathcal{C}_1(t^2)$
$\mathcal{R}(t^3;111)$
Primary
Primary
Primary
t^0
t^1
t^2
t^3

Figure 7.2: Reservoir State Possibilities for Irreversible Mutually-Exclusive Decision Pathways.

7.2 Operational Modes

Operational modes will depend on the probability structure of macroeconomic scenarios. The model system considers an early abandonment option and temporary suspensions of pooled production[18]. Three modes of operation will apply for each recovery stage:

- production under active control policy
- temporary suspension of pooled field-wide production
- early abandonment

These operational modes are context sensitive to the contemporaneous recovery stage. Primary and secondary recovery stages will have their own operating policies that establish decision rules for switching between operational modes.

If the early abandonment option is exercised, then the overall project will be terminated and all wells will be permanently shut in. This is a terminal mode that prunes all future branches and sets the production rate $Q(t)=0$ for all future time. Early abandonment may result from a contemporaneous shift in the economic limit due to low oil price expectations.

All operating wells will be collectively shut in if the contemporaneous recovery stage is suspended. The pooled production rate is $Q(t)=0$ while in suspended mode. This mode can occur when the contemporaneous oil price dips below a critical price level and the compounded value of fixed costs is less than the abandonment expense. Suspension is a reversible mode. The operation can switch back and forth between active production and pooled suspension modes. Because of the transient nature in the physical mechanisms governing porous media flow, the reservoir will change state along two different depletion pathways in response to the two control possibilities under active or suspended production modes. This implies that when the price changes state about the critical level, bifurcation in future control becomes path dependent on past actions (Figure 7.3). Bifurcation in reservoir depletion paths on each transition about the critical switching price cascades future control, investment and abandonment decisions into a infinite myriad of combinatorial instances.

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[18] A more rigorous analysis would consider the suspension policy for individual wells. This would involve a combinatorial exploration over an increased space of depletion state transitions. This is beyond the computational capacity of the present model with the available hardware.

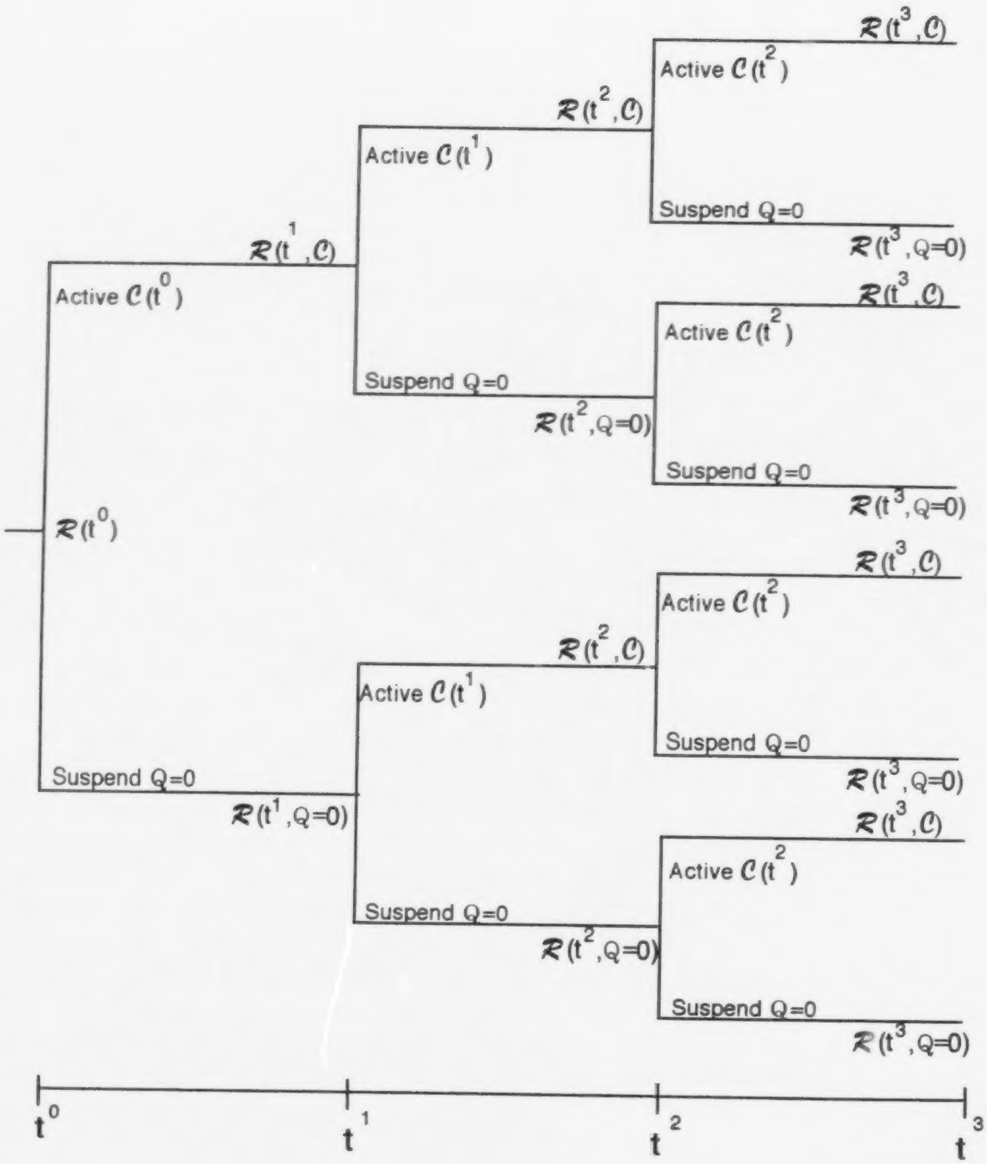

$\mathcal{R}(t^3,\mathcal{C})$
Active $\mathcal{C}(t^2)$
$\mathcal{R}(t^2,\mathcal{C})$
Active $\mathcal{C}(t^1)$
Suspend Q=0
$\mathcal{R}(t^1,\mathcal{C})$
$\mathcal{R}(t^3,Q=0)$
Active $\mathcal{C}(t^0)$
$\mathcal{R}(t^3,\mathcal{C})$
Active $\mathcal{C}(t^2)$
Suspend Q=0
$\mathcal{R}(t^2,Q=0)$
Suspend Q=0
$\mathcal{R}(t^3,Q=0)$
$\mathcal{R}(t^0)$
$\mathcal{R}(t^3,\mathcal{C})$
Active $\mathcal{C}(t^2)$
$\mathcal{R}(t^2,\mathcal{C})$
Active $\mathcal{C}(t^1)$
Suspend Q=0
Suspend Q=0
$\mathcal{R}(t^3,Q=0)$
$\mathcal{R}(t^1,Q=0)$
$\mathcal{R}(t^3,\mathcal{C})$
Active $\mathcal{C}(t^2)$
Suspend Q=0
$\mathcal{R}(t^2,Q=0)$
Suspend Q=0
$\mathcal{R}(t^3,Q=0)$
t^0
t^1
t^2
t^3

Figure 7.3: Path-Dependent Control and Bifurcation of Depletion Paths from Switching Operation Modes

7.3 Near-State Variables

Reservoir depletion paths determine oil production from the pool. These paths are not only functions of time, but also functions of the nested operating and control policies that depend on the reservoir depletion state. The dimension of reservoir state variables and bifurcating depletion paths complicate the deterministic measurement for contemporaneous production response and the prediction of future production rates. The model system deals with this problem by approximating the true reservoir state with near-state variables. Primary and secondary near-state variables ($\mathcal{P}_1, \mathcal{P}_2$) are defined as the cumulative pooled oil production from respective recovery stages.

$$\mathcal{P}_1(t) = \int_{t^0}^{t} Q_o(\tau)d\tau = \sum_{\substack{\text{primary}\\ \text{producers}}} \int_{t^0}^{t} Q_o(\tau)d\tau \qquad \text{Primary Production}$$

$$\mathcal{P}_2(t) = \int_{t^0}^{t} Q_o(\tau)d\tau = \sum_{\substack{\text{secondary}\\ \text{producers}}} \int_{t^0}^{t} Q_o(\tau)d\tau \qquad \text{Secondary Production} \tag{7.2}$$

The model assumes that primary production rates under active control policy and suspended pool operational modes can be uniquely determined as a function of the pooled cumulative primary oil production ($\mathcal{P}_1$). Furthermore, for a particular originating primary near-state ($\mathcal{P}_1$), waterflood production rates along secondary branches can be determined uniquely by the pooled cumulative secondary oil production ($\mathcal{P}_2$).

$$\begin{aligned} Q &= Q(\mathcal{P}_1) && \text{Primary Production} \\ Q &= Q(\mathcal{P}_2\,;\mathcal{P}_1) && \text{Secondary Production} \end{aligned} \tag{7.3}$$

The argument behind this premise is based on decline curve analysis. For a particular recovery stage with a given well configuration and active control policy, the active depletion state will follow a unique path in time. Production rates that can be determined as unique functions of time, can be equivalently expressed in terms of cumulative oil production. If production were to stop suddenly, then all flowing bottomhole pressures would stabilize towards static levels. In the absence of large gravitational and interfacial forces, static pressures would reach equilibrium after a short stabilization period. If production were to resume back to the same active controls as before, then bottomhole pressures would continue with the same active trend after an initial transient response. Production rates would pick up where they left off. If the transient response is negligible, then suspension would only shift the active production rate curve by the suspension period (Figure 7.4). The suspension period is filtered out when rate is expressed in terms of cumulative oil. The actively-controlled and suspended rate functions become virtually identical in terms of cumulative oil, except for transient deviations from suspension events. With this near-state transformation, bifurcating depletion paths essentially lead to the same production rates.

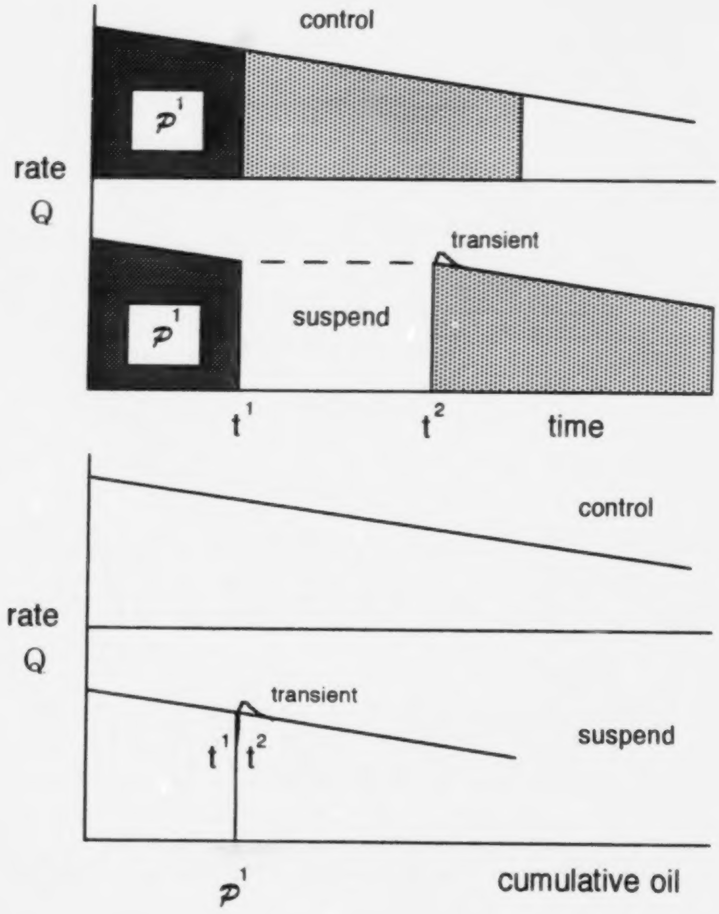

control
$\mathcal{P}^1$
rate
Q
transient
$\mathcal{P}^1$
suspend
t^1
t^2
time
control
rate
Q
transient
t^1
t^2
suspend
$\mathcal{P}^1$
cumulative oil

Figure 7.4: Transient Deviation in Near-State Variables

The near-state concept assumes that the suspension period is large with respect to the monthly bang-bang control policy. Transient effects will show some divergence between temporarily suspended operations and those without suspension in the time domain. These differences are smoothed out upon integration in the cumulative oil production domain.

Unique depletion paths can be traced in the feasible region of ($\mathcal{P}$, t) space as shown in Figure 7.5. The feasible depletion region is bounded by the cumulative oil production limit as determined by a sustained active control policy. Depletion path segments that are constant correspond to suspended modes of operation. Path segments that run along directions of increasing cumulative production ($\mathcal{P}$) correspond to operations under active control policy.

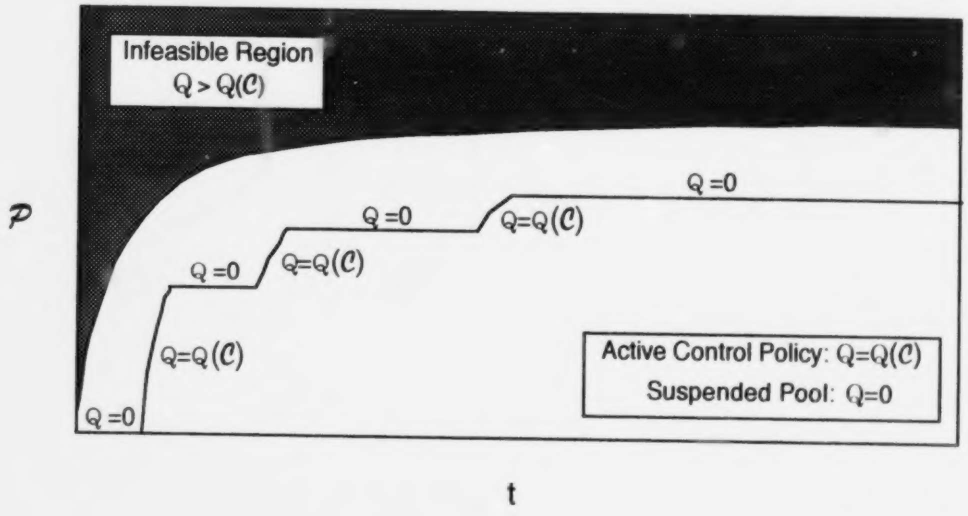


Figure 7.5: Unique Depletion Path in ($\mathcal{P}$,t) Space

7.4 Cumulative Production Tree

Cumulative oil intervals of equal volume are used to partition the ($\mathcal{P}_1$, $\mathcal{P}_2$) domain. Figure 7.6(a) shows the cumulative oil production tree. Five secondary waterflood branches, labelled (A) through (E), are forecast at 200 MSTB primary oil intervals starting from 1-Oct-95. All cumulative forecasts measure total production from the starting reference date. The ultimate primary oil recovery remaining is forecasted at 843 MSTB. Cumulative secondary oil decreases with waterflood delay, as indicated by total recoveries posted at the end of each consecutive branch. A maximum remaining waterflood recovery of 9.7 MMSTB is predicted for the earliest time and a minimum of 8.7 MMSTB is predicted for the latest time. Figure 7.6(b) shows the forecasted cumulative gas production tree. Cumulative gas increases significantly with waterflood delay. Figure 7.6(c) and (d) shows the forecasted cumulative water production and injection trees. Both cumulative water production and cumulative water injection peak at branch (D). Figure 7.6(e) shows the average reservoir pressure tree with predicted primary pressure decline and waterflood repressurization branches.

7.5 Time-Averaged Production Rates

Investment and operating decisions depend on cash flow projections. Cash flow depends on production rate. Decisions may be continuously polled along depletion branches or made at discrete decision times. Decisions can also be made at cumulative oil production milestones. Production rates representative of daily operations may have large fluctuating cycles as seen in Figure 5.4(a) and 6.5(a). These short-term oscillations can lead to misleading results from an economic evaluation. Time-averaging will smooth rates over periods of time more representative of the decision process. These periods are chosen to coincide with the cumulative oil partition. Time-averaged production rates can be determined from the incremental slope along depletion pathways:

$$\begin{aligned} Q_o &= \frac{d\mathcal{P}}{dt} && \text{Active Control Policy} \\ Q_o &= 0 && \text{Suspended Pool} \end{aligned} \qquad (7.4)$$

Table 7.1(a) tabulates the cumulative time (t_o) for oil production to reach its cumulative milestone partition under the active control policy. The ($M_1 \times M_2$) partition has $M_1=9$ intervals of $\Delta\mathcal{P}_1=100$ MSTB along the primary branch and a maximum of $M_2=20$ intervals of $\Delta\mathcal{P}_2=500$ MSTB along secondary branches. Cumulative oil times have been interpolated between simulated secondary branches to provide higher resolution. Table 7.1(b) tabulates the average oil rate (Q_o) between cumulative oil intervals ($\Delta\mathcal{P}_1, \Delta\mathcal{P}_2$). The oil rate posted at each milestone is the average rate measured from the previous milestone. For example, an average oil rate $Q_o(\mathcal{P}_1=0, \mathcal{P}_2=500)=1363$ STB/day over $t_o(0,500)=367$ days produces $\Delta\mathcal{P}_2=500$ MSTB of secondary oil in the earliest waterflood branch.

$$\begin{aligned} Q_o(\mathcal{P}_1^{m_1},0) &= \frac{[\mathcal{P}_1^{m_1} - \mathcal{P}_1^{m_1-1}]}{[t_o(\mathcal{P}_1^{m_1},0) - t_o(\mathcal{P}_1^{m_1-1},0)]} && ;\, m_1 = 1,2,\ldots,M_1 - 1 \\ Q_o(\mathcal{P}_1^{m_1},\mathcal{P}_2^{m_2}) &= \frac{[\mathcal{P}_2^{m_2} - \mathcal{P}_2^{m_2-1}]}{[t_o(\mathcal{P}_1^{m_1},\mathcal{P}_2^{m_2}) - t_o(\mathcal{P}_1^{m_1},\mathcal{P}_2^{m_2-1})]} && ;\, m_2 = 1,2,\ldots,M_2^{m_1} - 1 \end{aligned} \qquad (7.5)$$

Branch endpoints track partial intervals. The product of average rate at the branch endpoint and the time interval from the previous milestone gives the remaining cumulative oil recoverable along that branch.

$$\begin{aligned}\Delta\mathcal{P}_1^{M_1} &= Q_o(\mathcal{P}_1^{M_1},0) \times [t_o(\mathcal{P}_1^{M_1},0) - t_o(\mathcal{P}_1^{M_1-1},0)] \\ \Delta\mathcal{P}_2^{M_2^{m_1}} &= Q_o(\mathcal{P}_1^{m_1}, \mathcal{P}_2^{M_2^{m_1}}) \times [t_o(\mathcal{P}_1^{m_1},\mathcal{P}_2^{M_2^{m_1}}) - t_o(\mathcal{P}_1^{m_1},\mathcal{P}_2^{M_2^{m_1}-1})]\end{aligned} \qquad (7.6)$$

Table 7.2(c) tabulates the average gas rate for the cumulative oil partition. Gas rates are calculated in the same manner using cumulative gas production forecasts. Figure 7.7(a) and (b) show the time-averaged oil and gas production rates for primary and secondary branches in the production tree.

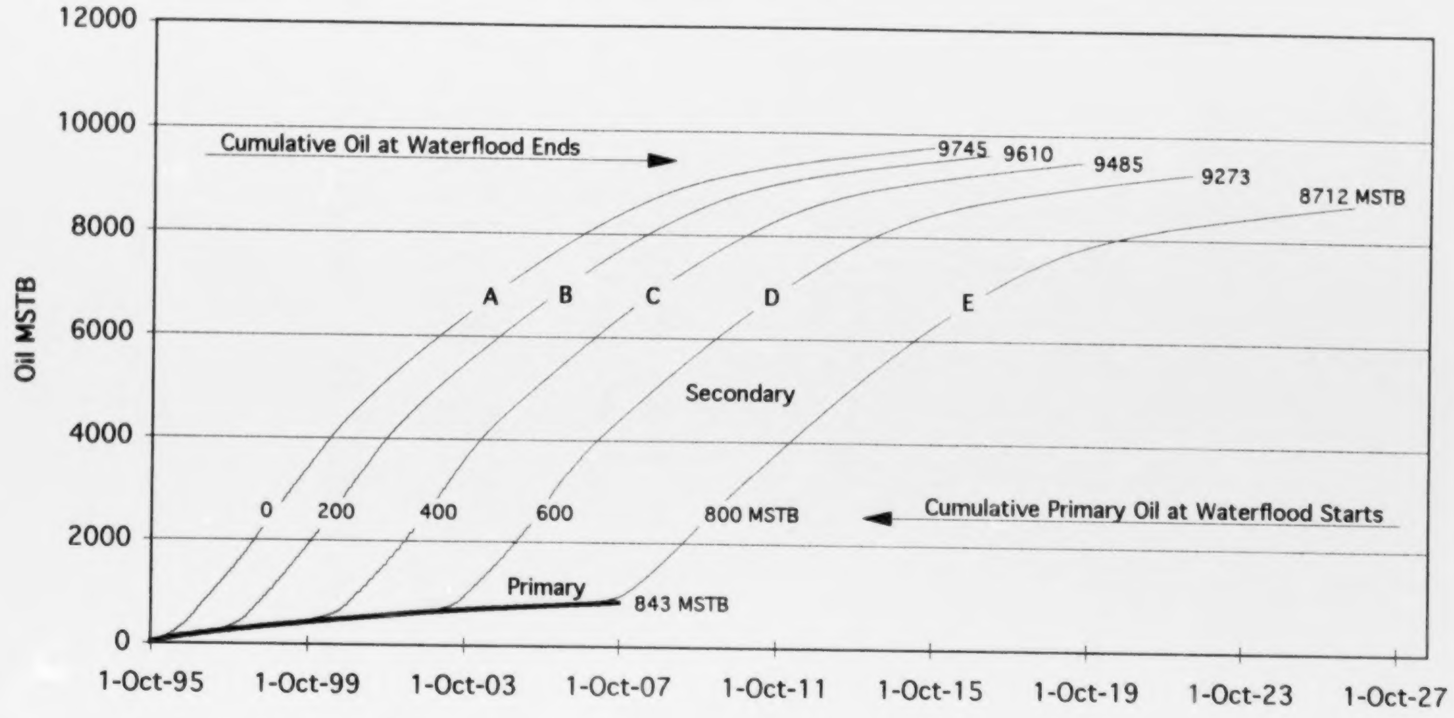


Figure 7.6(a): Cumulative Oil Branches

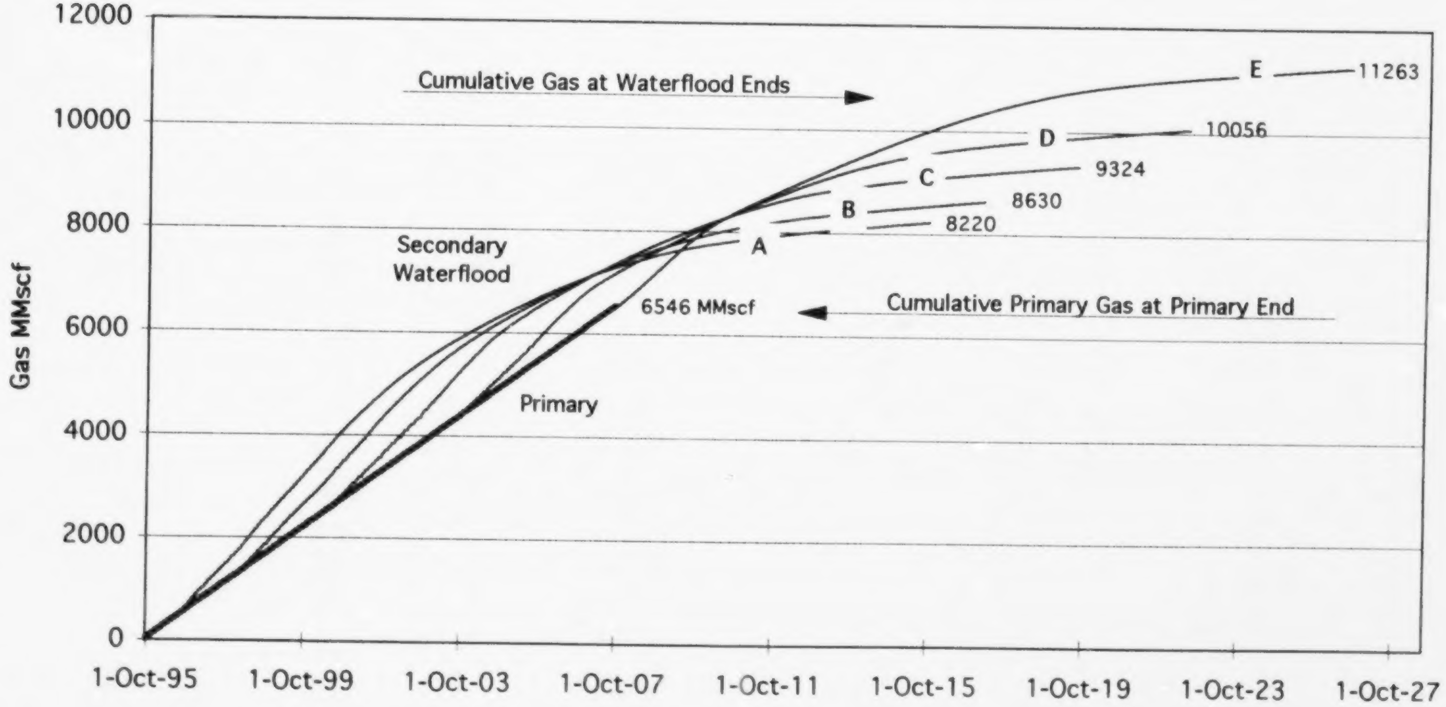


Figure 7.6(b): Cumulative Gas Branches

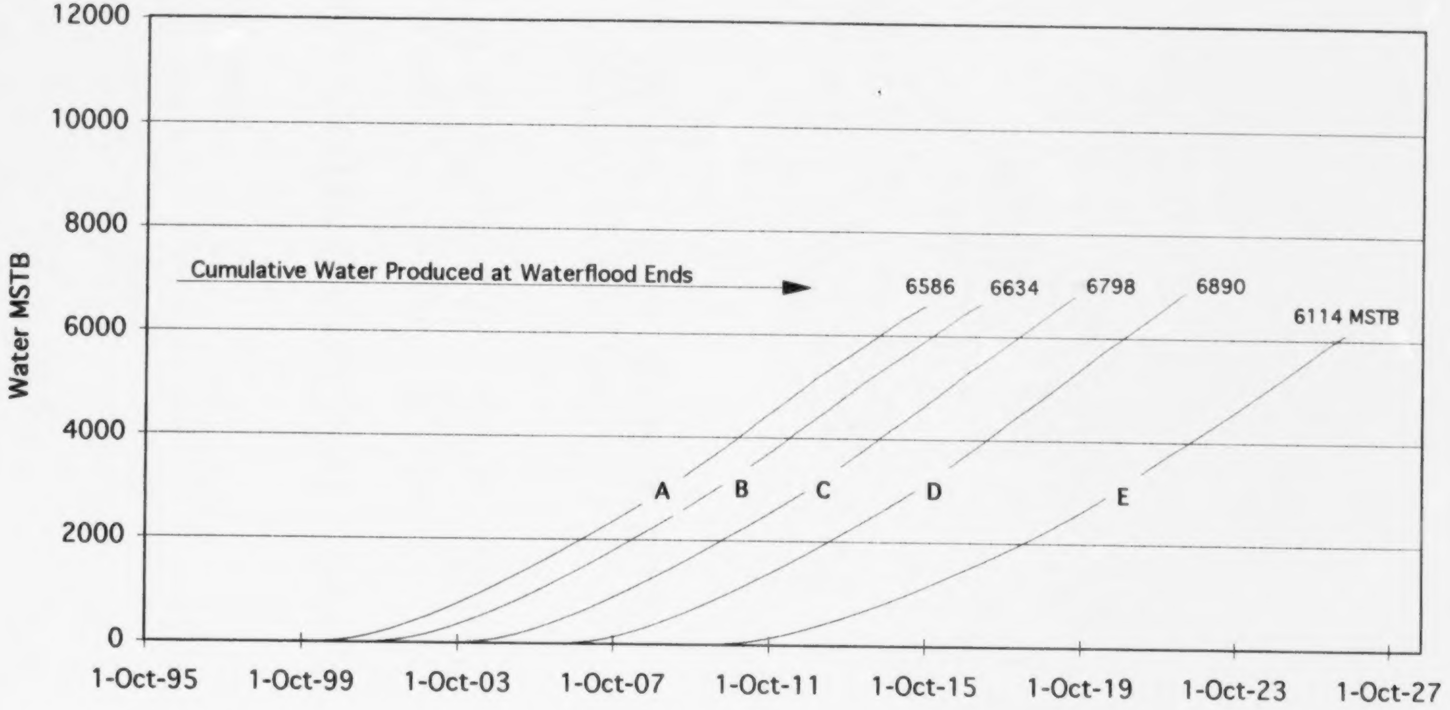


Figure 7.6(c): Cumulative Water Production Branches

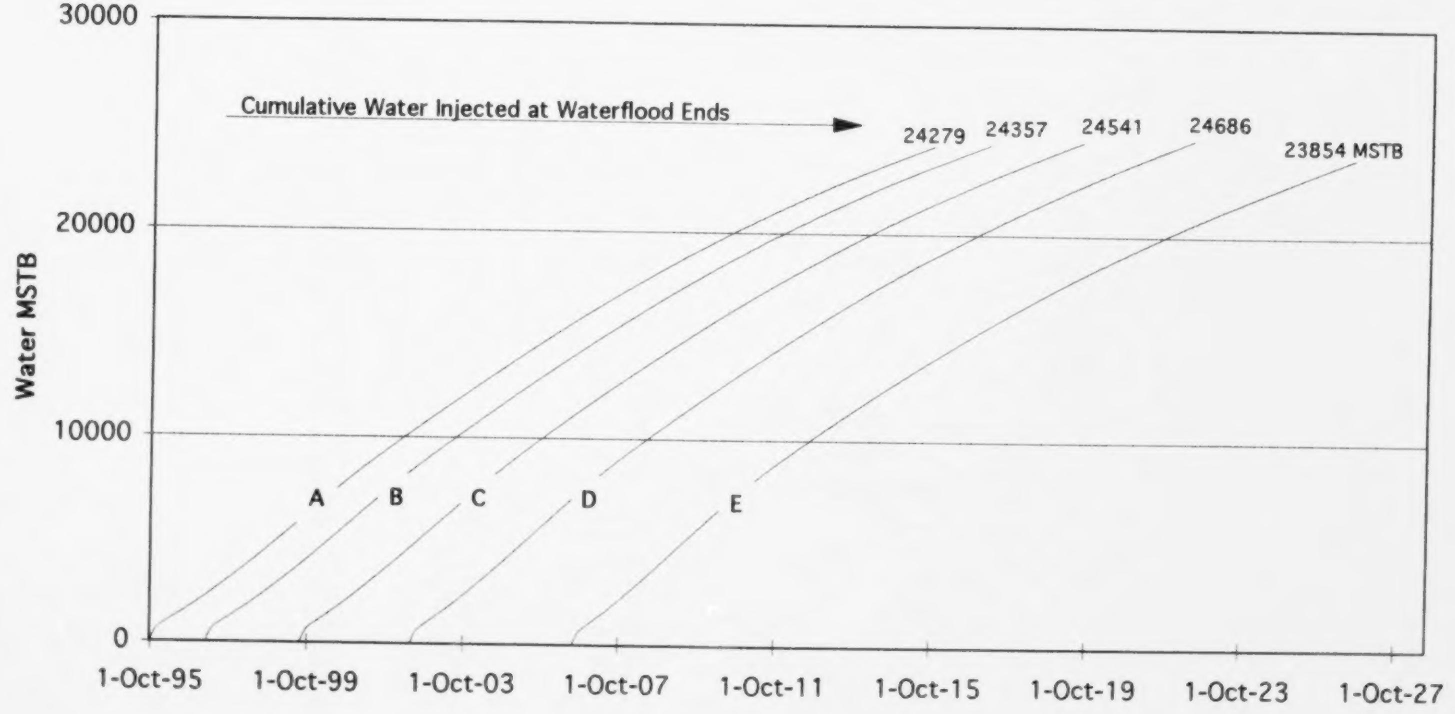


Figure 7.6(d): Cumulative Water Injection Branches

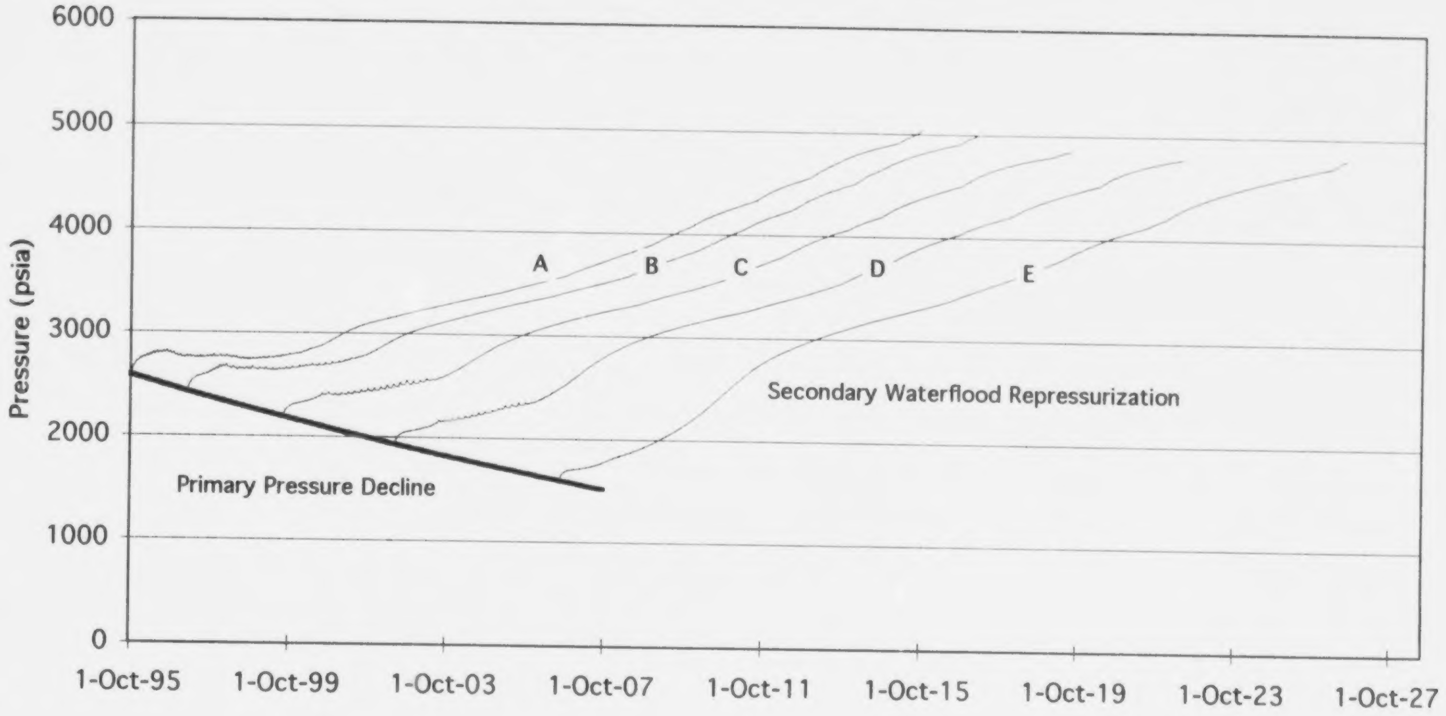


Figure 7.6(e): Average Reservoir Pressure Branches

$\mathcal{P}_1 \backslash \mathcal{P}_2$	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	0	367	565	768	949	1128	1301	1478	1666	1872	2120	2385	2676	2981	3299	3642	4022	4467	5078	6356	7306
100	215	607	811	1016	1200	1379	1549	1725	1913	2132	2385	2660	2955	3262	3587	3940	4337	4817	5585	6960	7519
200	521	950	1162	1371	1559	1738	1903	2077	2267	2504	2765	3053	3353	3664	3998	4366	4786	5317	6308	7623	0
300	943	1401	1615	1828	2016	2194	2354	2533	2739	2989	3258	3544	3841	4155	4500	4883	5335	5997	7292	8245	0
400	1401	1890	2106	2323	2512	2688	2844	3028	3251	3515	3793	4076	4371	4653	5044	5444	5931	6734	8359	8703	0
500	1893	2414	2641	2855	3040	3213	3385	3590	3831	4099	4378	4668	4973	5304	5673	6106	6711	7838	9195	0	0
600	2437	2993	3234	3443	3625	3795	3964	4213	4475	4746	5027	5323	5640	5966	6370	6839	7575	9061	9741	0	0
700	3107	3690	3938	4158	4365	4571	4791	5036	5303	5583	5875	6186	6524	6902	7364	8103	9167	10398	0	0	0
800	3989	4607	4865	5100	5340	5592	5854	6119	6394	6684	6992	7322	7686	8108	8672	9707	11203	0	0	0	0
843	4383	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 7.1(a): Cumulative Oil Production (MSTB) Milestone Times (days), $t_o(\mathcal{P}_1,\mathcal{P}_2)$.

$\mathcal{P}_1 \backslash \mathcal{P}_2$	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	0	1363	2519	2470	2754	2801	2891	2617	2660	2424	2019	1885	1719	1641	1572	1456	1315	1124	818	392	258
100	466	1274	2451	2434	2718	2796	2949	2838	2653	2284	1975	1822	1696	1626	1541	1415	1260	1041	651	364	197
200	326	1155	2381	2384	2666	2789	3036	2870	2634	2109	1914	1739	1665	1605	1497	1300	1190	942	505	275	0
300	237	1092	2338	2343	2659	2816	3110	2797	2432	2000	1858	1751	1681	1591	1451	1305	1106	756	386	271	0
400	218	1014	2314	2301	2649	2847	3135	2723	2245	1893	1800	1763	1697	1577	1493	1251	1026	622	308	251	0
500	203	960	2196	2343	2698	2888	2910	2433	2074	1871	1790	1727	1637	1512	1353	1155	826	444	288	0	0
600	184	895	2079	2382	2754	2934	2649	2176	1913	1847	1779	1649	1574	1447	1302	1066	679	336	254	0	0
700	149	858	2016	2270	2419	2430	2270	2040	1869	1792	1710	1608	1479	1323	1083	676	470	282	0	0	0
800	113	769	1932	2125	2066	1961	1911	1865	1815	1724	1627	1512	1358	1190	846	457	278	0	0	0	0
843	116	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 7.1(b): Average Oil Rate (STB/day) between Cumulative Oil Milestones (MSTB), $Q_o(\mathcal{P}_1,\mathcal{P}_2)$.

$\mathcal{P}_1 \backslash \mathcal{P}_2$	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	0	1643	2401	2244	2364	2401	2429	2343	2360	2359	2002	1800	1493	1274	1132	1020	907	751	540	252	192
100	1557	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
200	1566	1700	2253	2139	2137	2188	2385	2312	2402	2052	1650	1507	1265	1143	1045	930	804	609	343	203	0
300	1415	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
400	1506	1720	2244	2071	2117	2216	2499	2242	2087	1525	1309	1182	1110	1010	891	794	629	385	210	174	0
500	1538	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
600	1466	1821	1940	2036	2145	2232	2035	1622	1349	1125	1074	1019	934	838	751	534	381	209	187	0	0
700	1483	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
800	1486	1540	[illegible]	1876	1450	1093	971	941	917	873	827	773	702	595	443	243	159	0	0	0	0
843	1484	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 7.1(c): Average Gas Rate (Mscf/day) between Cumulative Oil Milestones (MSTB), $Q_g(\mathcal{P}_1,\mathcal{P}_2)$.

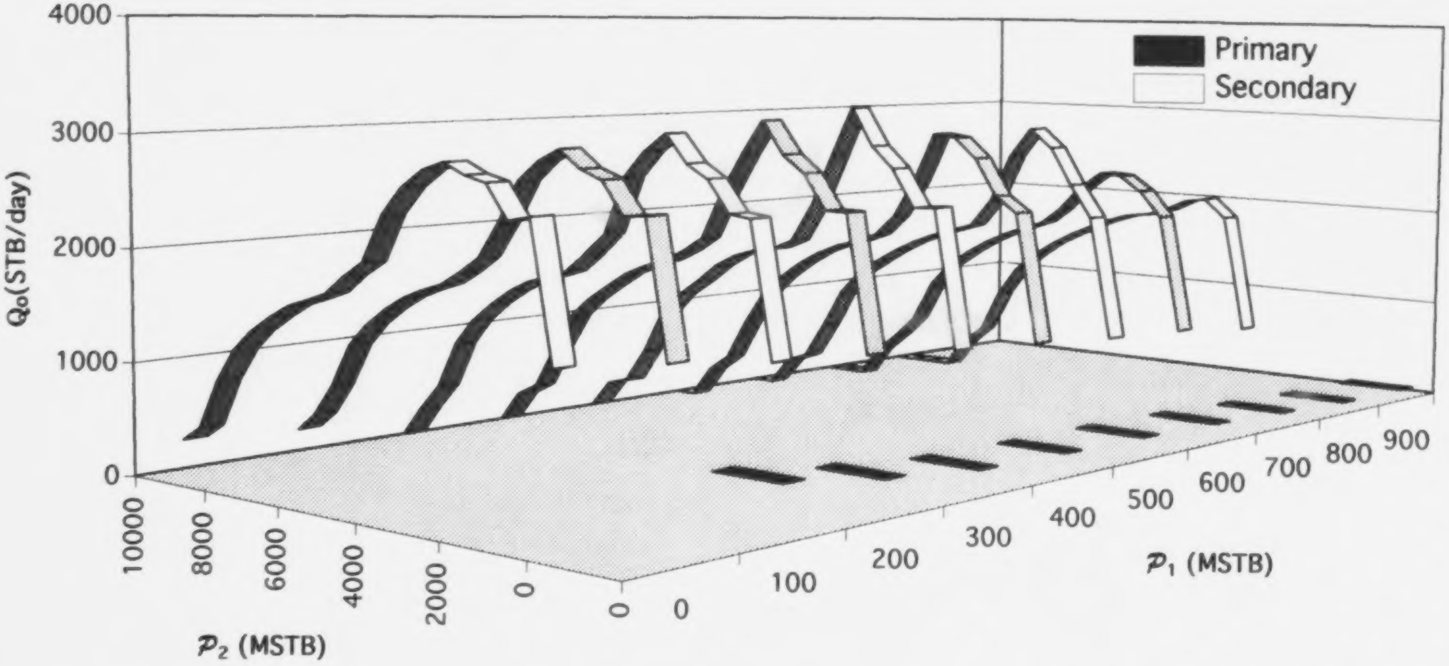


Figure 7.7(a): Average Pool Oil Rate between Cumulative Oil

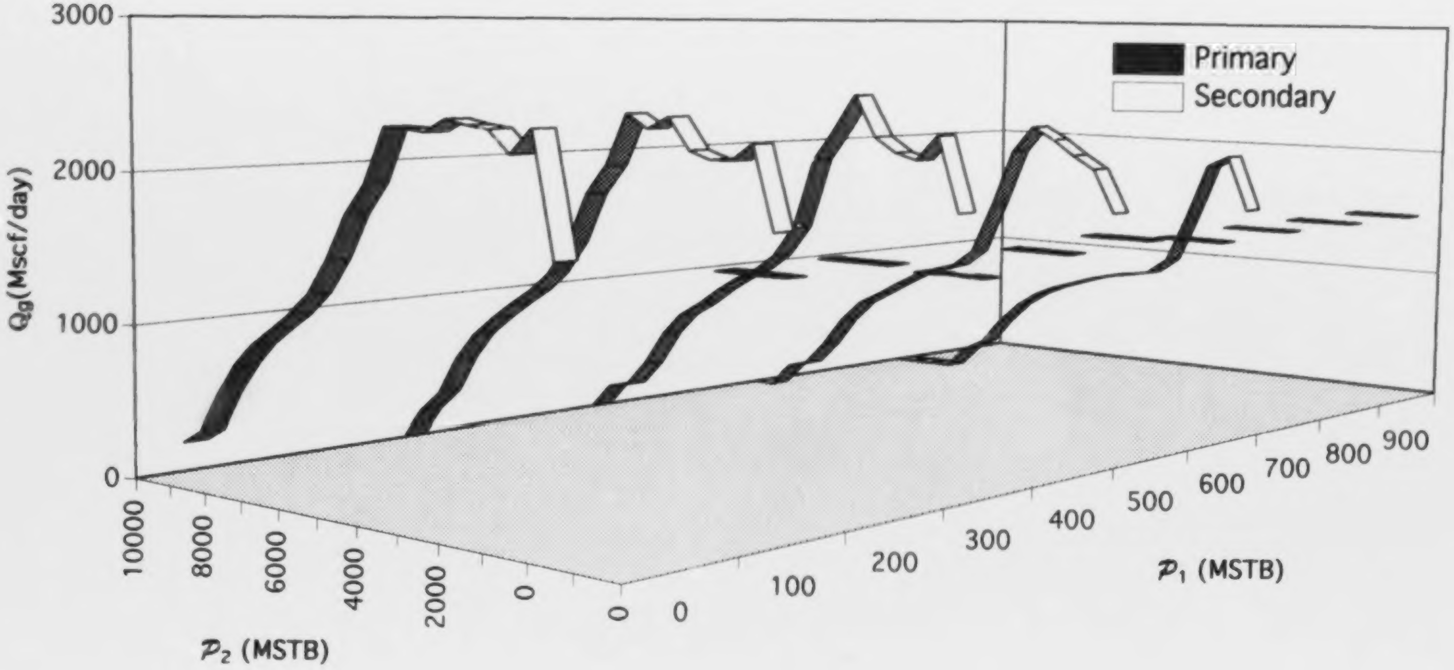


Figure 7.7(b): Average Pool Gas Rate between Cumulative Oil

Chapter 8: Depletion Strategy Model

8.1 Strategic Decisions

The depletion strategy ($\mathscr{D}$) establishes price-sensitive decision rules to maximize production value over the space of allowable operating choices. The optimization problem is formulated to maximize operations value contingent on the investment timing decision for a design secondary recovery project.

Production value ($\mathscr{V}$) of remaining operating alternatives over the producing life cycle ($0 \leq t \leq T$) depends exogenously on the contemporaneous spot price of oil, s(t). Remaining production value also depends on the contemporaneous depletion state, as represented by cumulative oil production ($\mathcal{P}_1$, $\mathcal{P}_2$), and the depletion strategy ($\mathscr{D}$) followed in producing the reservoir.

$$\mathscr{V} = \mathscr{V}(s, t, \mathcal{P}_1, \mathcal{P}_2; \mathscr{D}) \qquad (8.1)$$

The depletion strategy ($\mathscr{D}$) involves price-sensitive investment decisions for choosing between alternative depletion paths. Primary and secondary paths have separate operating policies (Θ_1, Θ_2) with context sensitive decision rules to choose between three mutually exclusive modes of operation (Figure 8.1). The three modes of primary and secondary operation (θ_{1m}, θ_{2m}; m=C,S,A) are active control, pool suspension and early abandonment as described in Section 7.2. Active production modes (θ_{1C}, θ_{2C}) for primary and secondary stages operate under the corresponding control policy ($\mathcal{C}_1, \mathcal{C}_2$) established to meet design objectives subject to regulatory constraints. Passive production modes (θ_{1S}, θ_{2S}) suspend field operations ($Q_1=0, Q_2=0$). Terminal production modes (θ_{1A}, θ_{2A}) abandon the operation early.

8.2 Strategy Duration

The depletion strategy ($\mathscr{D}$) for Chedderville Viking "A" will apply over a fixed duration strategic window ($0 \leq t \leq T$) that spans a complete set of producing life possibilities. The earliest time in the feasible waterflood timing window establishes the start time ($t=0$) on the calendar date 1-Oct-95. Primary production is planned to terminate at the end of twelve years under the primary control policy (θ_{1C}). A design waterflood is planned for a twenty year secondary life cycle under control (θ_{2C}) over primary depletion states ($\mathcal{P}_1$) in a ten year timing window. The depletion state will not change while primary operations are suspended (θ_{1S}). If primary operations are temporarily suspended, then the calendar time of the waterflood window will be extended by the suspension period. The design waterflood could potentially start at any time ($0 \le t \le T$). The depletion strategy fixes the overall decision policy duration ($T=32$ years) to coincide with consecutive primary and secondary life cycles. This fixed duration allows some slack time for the depletion strategy. The actual duration may be less if the project is abandoned early.

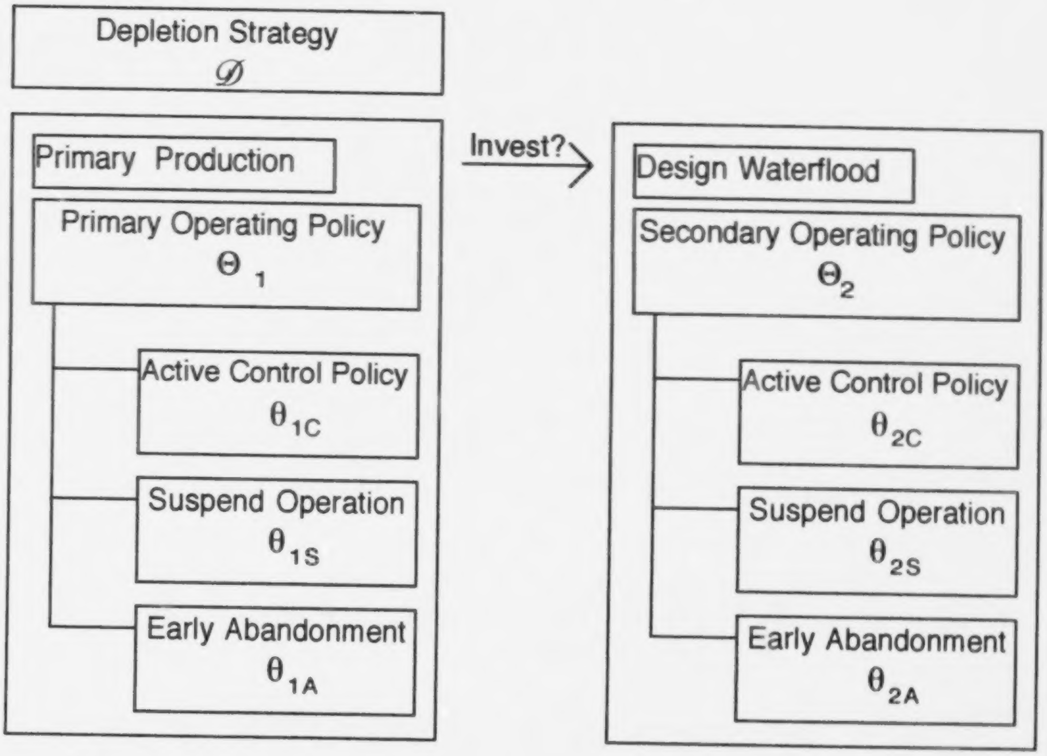

Depletion Strategy
$\mathscr{D}$
Primary Production
Primary Operating Policy
Θ_1
Active Control Policy
θ_{1C}
Suspend Operation
θ_{1S}
Early Abandonment
θ_{1A}
Invest?
Design Waterflood
Secondary Operating Policy
Θ_2
Active Control Policy
θ_{2C}
Suspend Operation
θ_{2S}
Early Abandonment
θ_{2A}

Figure 8.1: Strategic Decision Hierarchy for Operations and Investment

8.3 Project Costs

The operation is assumed to have exhausted economic reserves by the end of the strategic window. A lump sum mandatory abandonment expense must be incurred at the terminal time. The abandonment expense (A_1, A_2) depends on the contemporaneous recovery stage at the time of termination ($t=T$). A lump sum capital cost (K_{12}) must be sunk to implement the design waterflood. The investment decision to shift from primary to secondary recovery stages is irreversible and mutually exclusive. The operation of each recovery stage has an associated cost schedule for fixed costs (f_1,f_2) and variable unit costs (v_1,v_2). Typical operating costs for Alberta oilfields were obtained through direct consultation with the Alberta Department of Energy[19]. These included:

- average fixed operating costs per well
- average variable operating costs per barrel of oil produced
- water injection conversion costs
- well abandonment costs correlated with depth

The mean abandonment cost per well is correlated to the depth (z) in meters:

$$A = 16871 - 4.8393\,z + 0.009267\,z^2 + 0.0000002\,z^3 \qquad (8.2)$$

The historical capital cost for new wells in the Viking "A" pool was \$1.2 million. Capital, operating and abandonment costs for each recovery stage are listed in Table 8.1. The waterflood capital cost is estimated at \$32.4 million, fixed costs at \$100/day/well and variable costs at \$2/STB oil. All gas is to be flared and not gathered, so that no benefits or costs are associated with gas production.

8.4 Cash Flow Model

Cash flow and income tax accounting calculations are shown in Table 8.2 (CIM Petroleum Society Monograph No. 1, 1994). The model will use a simplified before-tax cash flow ($\mathcal{Cf}$) calculation that depends on continuous production revenues, operating costs and a single lumped royalty rate. Gross revenue projections will come directly from oil production forecasts (Q) and the oil price (s). Model royalties will be paid out at a fixed royalty rate percentage (R=23%) of gross revenues. Cash flow before tax ($\mathcal{Cf}$) will depend on the recovery stage (Θ_i).

$$\mathcal{Cf}(s,t,Q_i\,;\,\Theta_i) = [(1-R)\,s(t) - v_i]\,Q_i - f_i \qquad (8.3)$$

---

[19] Consultation with John E. Faltinson, Alberta Department of Energy.

Primary Production Costs	Unit Cost per Well	Number of Wells	$Amount
Infill Drilling	$1,200,000	0	$0
Total Capital Cost			**$0**
Abandon Wells @ 8600 ft Depth	$71,500	14	$1,001,000
Field Abandonment Cost			**$1,001,000**
Fixed Monthly Operating Cost	$3,000	14	$42,000
Total Fixed Montly Operating Cost			**$42,000**

Variable Operating Cost = $2.00/STB Oil + $0.80/Mscf Gas Gathered

Waterflood Project Costs	Unit Cost per Well	Number of Wells	$Amount
Infill Drilling	$1,200,000	23	$27,600,000
Conversion to Water Injection	$300,000	16	$4,800,000
Total Capital Cost			**$32,400,000**
Abandon Wells @ 8600 ft Depth	$71,500	37	$2,645,500
Field Abandonment Cost			**$2,645,500**
Fixed Montly Operating Cost	$3,000	37	$111,000
Total Fixed Monthly Operating Cost			**$111,000**

Variable Operating Cost = $2.00/STB Oil + $0.80/Mscf Gas Gathered

Table 8.1: Project Capital, Operating and Abandonment Costs

	Income Tax	Earned Depletion	Resource Allowance	Cash Flow
Gross Revenue				
Working Interest	+	+	+	+
Production Royalty	+	+	+	+
Deemed Income	+	+	+	
Expenses				
Crown Royalty				-
Mineral Tax				-
Production Royalty	-	-	-	-
Lease Operating	-	-	-	-
Crown Lease Rentals	-			-
CCA - Production	-	-	-	
G&A - Production	-	-	-	-
CEDOE			-	-
Adjusted Resource Profits (ARP)			Σ	
Resource Allowance (25% of ARP)	-	-		
Resource Royalty Income	+	+		+
Resource Royalty Expense	-	-		-
CCA-Other-Resource Profit	-			
G&A-Other	-	-		-
Interest	-	-		-
COGPE	-	-		
CDE	-	-		
CEE	-	-		
Resource Profits (RP)		Σ		
Earned Depletion (25% of RP)	-			
Other				
Foreign Income	+			+
Foreign Expense	-			-
Nonproduction Income	+			+
Nonproduction Expense	-			-
Net Income for Tax Purpose	Σ			
Cash Flow before Income Tax				Σ

Table 8.2 : Oil and Gas Accounting for Cash Flow and Income Tax (Alberta)

8.5 Oil Price Model

The spot price s(t) at the current time ($t=t^0$) is known with certainty. The spot price at any future time ($t^0<t\leq T$) will be in some state of uncertainty. Asset valuation will depend on the price model used to forecast future spot oil prices. Discounted cash flow methods assume a price model where the future spot price can be forecast with certainty. Modern asset pricing methods assume a stochastic price model that explicitly accounts for this uncertainty. The price model used in this work assumes a continuous stochastic Gauss-Wiener process where future oil price expectations depend on the current oil price state and a non-stochastic oil price volatility.

Volatility estimates are based on the historical average monthly spot oil prices[20] listed in Table 8.3 and plotted in Figure 8.2. The price volatility (σ) is a measure of the variation in the proportional change in price over time (Hull 1991). The rate of proportional change in price is the rate of return in the spot market. The expected rate of return, is the rate of growth in the mean price trend (μ). The expected trend and annual volatility (σ) can be approximated with statistical point estimates. The continuously compounded rate of return (u^n),

$$u^n = \ln\left(\frac{s^n}{s^{n-1}}\right) \tag{8.4}$$

is calculated using price states (s^n) sampled at regular intervals $\{t^n=n\Delta t;\ n=0,1,\ldots N\}$ over the time period ($t^0\leq t^n\leq t^N$). The time interval Δt is measured in years. The mean rate of return (μ) is estimated by the arithmetic average, $\overline{u}$:

$$\overline{u} = \frac{1}{N}\sum_{n=0}^{N} u^n \tag{8.5}$$

Standard deviation in the rate of return ($\sigma\sqrt{\Delta t}$) is estimated by the sample statistic, $s\sqrt{\Delta t}$:

$$s\sqrt{\Delta t} = \sqrt{\frac{1}{N-1}\sum_{n=0}^{N}(u^n-\overline{u})^2} \tag{8.6}$$

---

[20] Dubai, U.K. Brent and Alaska Average, SPOT, F.O.B. (1991-1994) from The Monthly Commodity Price Bulletin.

Month	Monthly Average* Oil Price ($US/bbl)	Monthly Average Return (%)
Jan-91	$21.25	
Feb-91	$16.68	-24.21%
Mar-91	$17.05	2.19%
Apr-91	$17.50	2.61%
May-91	$17.68	1.02%
Jun-91	$17.03	-3.75%
Jul-91	$18.01	5.60%
Aug-91	$18.24	1.27%
Sep-91	$19.14	4.82%
Oct-91	$20.43	6.52%
Nov-91	$19.68	-3.74%
Dec-91	$16.72	-16.30%
Jan-92	$16.38	-2.05%
Feb-92	$16.68	1.81%
Mar-92	$16.52	-0.96%
Apr-92	$17.82	7.57%
May-92	$18.70	4.82%
Jun-92	$20.23	7.86%
Jul-92	$19.47	-3.83%
Aug-92	$18.77	-3.66%
Sep-92	$19.20	2.27%
Oct-92	$19.33	0.67%
Nov-92	$18.22	-5.91%
Dec-92	$17.26	-5.41%
Jan-93	$16.38	-5.23%
Feb-93	$17.45	6.33%
Mar-93	$17.78	1.87%
Apr-93	$17.80	0.11%
May-93	$17.52	-1.59%
Jun-93	$16.80	-4.20%
Jul-93	$15.72	-6.64%
Aug-93	$15.88	1.01%
Sep-93	$15.27	-3.92%
Oct-93	$15.82	3.54%
Nov-93	$14.50	-8.71%
Dec-93	$12.65	-13.65%
Jan-94	$13.49	6.43%
Feb-94	$13.36	-0.97%
Mar-94	$13.35	-0.07%
Apr-94	$14.84	10.58%
May-94	$16.09	8.09%
Jun-94	$16.54	2.76%
Jul-94	$17.37	4.90%
Aug-94	$16.51	-5.08%
Sep-94	$15.66	-5.29%
	Annual Price Volatility	23.33%
	Standard Error	2.49%

* Dubai, U.K. Brent and Alaska Average, SPOT, F.O.B.
(Monthly Commodity Price Bulletin)

Table 8.3: Oil Price Volatility

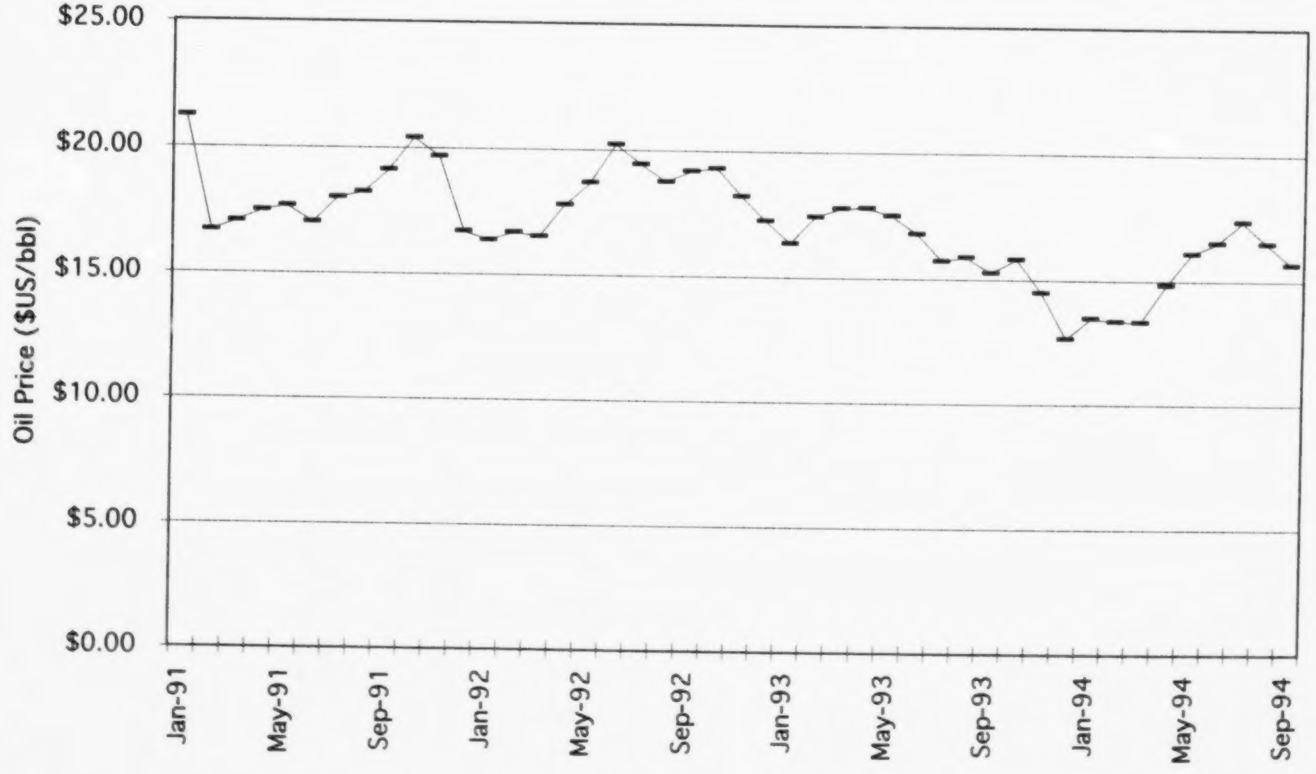


Figure 8.2: Average Monthly Spot Oil Price

The estimated annual volatility (σ=23.3%) has a standard error of 2.5%. Volatility time dependence is not considered here and assumed to be constant throughout the depletion strategy. The effects of the U.S. exchange rate on Canadian oil price volatility are not considered here.

The rate of return on the spot oil price is modelled as an exogenous continuous stochastic standard Gauss-Wiener process (Merton 1973):

$$\frac{ds}{s} = \mu dt + \sigma d\zeta \qquad (8.7)$$

where $d\zeta(t)$ is a normal random variable with variance dt; s(t) is the spot oil price at time t; $\mu(t)$ is the expectation of the continuously compounded rate of return on the spot market; and $\sigma(t)$ is the non-stochastic standard deviation in the rate of return. The solution of this differential random walk process is a lognormal distribution for the future spot price (Samuelson 1965).

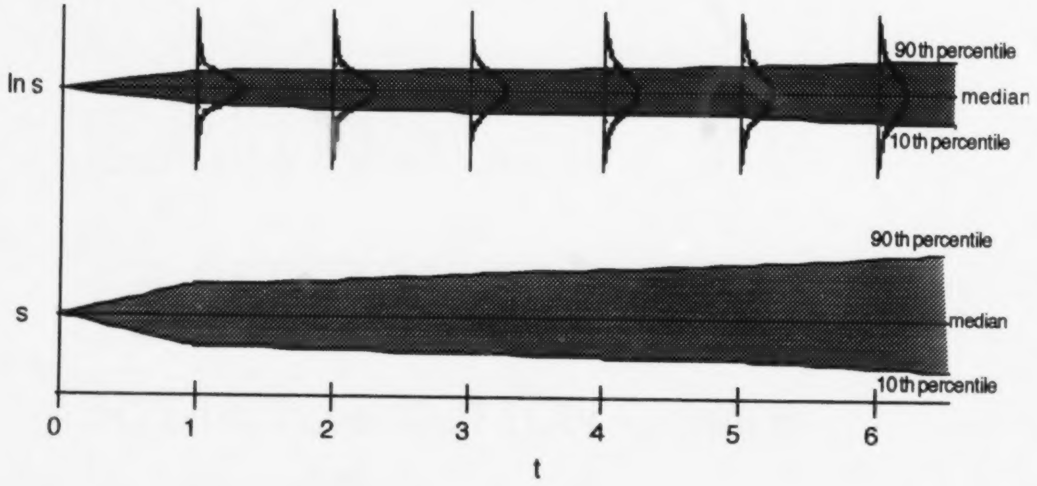


Figure 8.3: Lognormal Oil Price Expectations (μ=0)

The probability density measure (dm) for future price states $s(\tau)$ at time τ , given the price state s(t) at an earlier time t,

$$dm(\tau, s(\tau) \mid t, s(t)) = dLN[s(\tau)\,;\, s(t)e^{\mu(\tau-t)}, \sigma^2(\tau-t)] \qquad (8.8)$$

has a lognormal distribution $dLN[s;E,\sigma^2]$ in the spot price (s) with expectation (E) and associated variance (σ^2):

$$dLN[\,s(\tau);\,s(t)e^{\mu(\tau-t)},\,\sigma^2(\tau-t)] = \frac{1}{\sigma\sqrt{2\pi(\tau-t)}}\,e^{-[\frac{\ln\frac{s(\tau)}{s(t)}+\mu(\tau-t)}{\sigma\sqrt{2(\tau-t)}}]^2}\,ds(\tau) \tag{8.9}$$

The evolution of price state distributions are illustrated in Figure 8.3. The price distributions represent a continuous state of price uncertainty at future times. The variance of these distributions grow proportionally with time.

8.6 Asset Valuation Model

The asset valuation model assumes that production can be sold forward on the futures market, and that the production asset value can be replicated by a self-financing portfolio of commodity futures and risk free assets. Dynamic equilibrium models for the futures price (Samuelson 1965, Merton 1973) and asset value (Brennan and Schwartz 1985) are formulated by finding hedge ratios that eliminate the stochastic returns from the self-financing portfolios.

Holding oil in inventory will have additional benefits over holding other commodities strictly for investment (Hull 1991). These benefits include the ability to profit from temporary local shortages and the ability to keep an industrial process running (Brennan and Schwartz 1985). The flow of benefits that accrue from ownership provide a convenience yield to the owner. The convenience yield will vary between different inventory holders. Inventories in equilibrium will be held by those that have the highest convenience yield for a marginal unit of inventory, net of storage costs. If positive amounts are held in inventory, and competition among storers ensure a unique marginal net convenience yield, then the yield will vary inversely with the amount of oil held in inventory. The benefits that accrue from ownership will increase with shortages and decrease with gluts. The net convenience yield will correlate positively with the spot oil price. The marginal net convenience yield (C) in this model is assumed to be directly proportional to the spot price (s).

$$C(S,t) = c\,s(t) \tag{8.10}$$

The net marginal convenience yield rate per dollar unit of commodity held in inventory (c=5%) is assumed to be 2% higher than the real risk-free interest rate (r=3%). Nominal risk-free interest and inflation rates are based on 90-day treasury bills and the consumer price index[21] (1994). Term structure is not considered.

The futures price is assumed to be the theoretical forward price, which implies that the following assumptions (Cox *et al.*, 1981) hold throughout this formulation:

- the risk free rate is known with certainty
- borrowing rates are the same as the risk-free interest rate
- all trading profits are subject to the same tax rate
- transaction costs are negligible
- arbitrage opportunities disappear as soon as they arise, so that no arbitrage opportunities persist for any length of time

The contemporaneous futures price (F) for delivery at time (T) is a function of the stochastic spot price (s) and the time to maturity ($\tau = T - t$).

$$F = F(s, \tau) \tag{8.11}$$

Ito's lemma eliminates explicit dependence on the stochastic variable, $d\zeta$, and relates the total change in the futures price to the partial changes with respect to time and the contemporaneous spot price:

$$dF = \left(\frac{1}{2}\sigma^2 s^2 \frac{\partial^2 F}{\partial s^2} - \frac{\partial F}{\partial \tau}\right)dt + \frac{\partial F}{\partial s}ds \tag{8.12}$$

A Gauss Wiener process for the futures price is obtained using Ito's lemma (8.12) in conjunction with the instantaneous return on the spot price (8.7):

$$\frac{dF}{F} = \beta dt + \gamma d\zeta \tag{8.13}$$

where β is instantaneous expected rate of return on the futures contract:

$$\beta = F^{-1}\left[\frac{1}{2}\sigma^2 s^2 \frac{\partial^2 F}{\partial s^2} + \mu s \frac{\partial F}{\partial s} - \frac{\partial F}{\partial \tau}\right] \tag{8.14}$$

---

[21] Government of Canada 3-month treasury bills and consumer price index were obtained from Canadian Economic Observer (Nov 1994), Statistics Canada Catalogue No. 11-010 Monthly.

and γ is standard deviation in the rate of return on the futures contract:

$$\gamma = F^{-1}[\sigma s \frac{\partial F}{\partial s}] \qquad (8.15)$$

The no arbitrage assumption implies that a self-financing portfolio can be replicated with a long position in oil, a short position in oil futures contracts and funds borrowed at the risk free rate. This portfolio has W_1 (instantaneous) dollars invested in holding oil in inventory, W_2 dollars shorted in oil futures contracts and W_3 dollars borrowed at the risk free rate. Entering a futures contract involves no receipt or outlay of funds and borrowing is used to finance the long position in oil, such that the aggregate investment in the portfolio is zero (W_1-W_3=0). A self-financing portfolio requires zero investment and provides a zero expected return. The instantaneous return on the portfolio (dY), including the convenience yield, is a stochastic differential process:

$$dY = W_1(\frac{ds}{s} + cdt) - W_2\frac{dF}{F} - W_3 rdt \qquad (8.16)$$

Substitution of Gauss Wiener processes for spot and futures prices, (8.7) and (8.13), gives:

$$dY = [W_1\sigma - W_2\gamma]d\zeta + [W_1(\mu + c - r) - W_2\beta]dt \qquad (8.17)$$

A hedge ratio, or the proportion of dollar amounts invested between futures (W_2) and the commodity (W_1) are chosen so that the instantaneous return is non-stochastic.

$$W_2 = \frac{\sigma}{\gamma}W_1 = F[s\frac{\partial F}{\partial s}]^{-1}W_1 \qquad (8.18)$$

The expected return on the portfolio must also be zero:

$$(\mu + c - r)W_1 - \beta W_2 = 0 \qquad (8.19)$$

Substituting for W_1, W_2, and β from (8.14), (8.18) and (8.19):

$$(\mu + c - r) - [s\frac{\partial F}{\partial s}]^{-1}\{\frac{1}{2}\sigma^2 s^2 \frac{\partial^2 F}{\partial s^2} + \mu s\frac{\partial F}{\partial s} - \frac{\partial F}{\partial \tau}\} = 0 \qquad (8.20)$$

leads to a deterministic nonstationary second-order partial differential equation for the futures price (Samuelson 1965, Merton 1973):

$$\frac{1}{2}\sigma^2 s^2 \frac{\partial^2 F}{\partial s^2} + (r-c)s\frac{\partial F}{\partial s} - \frac{\partial F}{\partial \tau} = 0 \tag{8.21}$$

An analytical solution is obtained when the convenience yield is proportional to the spot price. The terminal condition that the futures price must converge to the spot price at maturity, gives:

$$F(s,0) = s \rightarrow F(s,\tau) = se^{(r-c)\tau} \tag{8.22}$$

This implies that the spot price (s) is a sufficient statistic to determine the futures price $F(s,\tau)$. For a given depletion strategy ($\mathcal{D}$), the instantaneous production value $\mathcal{V}(s,t,\mathcal{P}_1, \mathcal{P}_2;\mathcal{D})$ is a function of the contemporaneous spot price (s), time (t) and the depletion state ($\mathcal{P}_1$, $\mathcal{P}_2$). Ito's lemma eliminates explicit dependence on the stochastic variable, $d\zeta$, and relates the change in production value to the partial changes with respect to time, spot price and depletion state:

$$d\mathcal{V} = \frac{\partial \mathcal{V}}{\partial s}ds + \{\frac{\partial \mathcal{V}}{\partial t} + \frac{1}{2}\sigma^2 s^2 \frac{\partial^2 \mathcal{V}}{\partial s^2}\}dt + \frac{\partial \mathcal{V}}{\partial \mathcal{P}_1}d\mathcal{P}_1 + \frac{\partial \mathcal{V}}{\partial \mathcal{P}_2}d\mathcal{P}_2 \tag{8.23}$$

Production can be sold forward through futures contracts. A self-financing portfolio is replicated with W_1 dollars invested in a long position in oil production with asset value $\mathcal{V}$, W_2 dollars shorted in oil futures and W_3 dollars borrowed at the risk free rate (r). Entering the futures contract involves no receipt or outlay of funds and borrowing is used to finance the long position on oil production ($W_1=W_3$). A self-financing portfolio requires zero investment and provides a zero expected return. The instantaneous dollar return on the portfolio, dY, including the cash flows from production ($\mathcal{C}f$) is:

$$dY = W_1(\frac{d\mathcal{V}}{\mathcal{V}} + \frac{\mathcal{C}f}{\mathcal{V}}dt) - W_2\frac{dF}{F} - W_3 rdt \tag{8.24}$$

Using Ito's lemma (8.23) and substituting for the futures price, (8.13) and (8.21), yields:

$$dY = \frac{W_1}{\mathcal{V}}\{[\mathcal{C}f + \frac{\partial \mathcal{V}}{\partial t} + \frac{1}{2}\sigma^2 s^2 \frac{\partial^2 \mathcal{V}}{\partial s^2}]dt + \frac{\partial \mathcal{V}}{\partial s}ds + \frac{\partial \mathcal{V}}{\partial \mathcal{P}_1}d\mathcal{P}_1 + \frac{\partial \mathcal{V}}{\partial \mathcal{P}_2}d\mathcal{P}_2\}$$
$$- \frac{W_2}{F}[(c-r)s\frac{\partial F}{\partial s}dt + \frac{\partial F}{\partial s}ds] - W_3 r dt \qquad (8.25)$$

Rearranging terms with (W_1=W_3) gives:

$$dY = \{\frac{1}{\mathcal{V}}[\mathcal{C}f + \frac{\partial \mathcal{V}}{\partial t} + \frac{1}{2}\sigma^2 s^2 \frac{\partial^2 \mathcal{V}}{\partial s^2}] - \frac{W_2}{FW_1}(c-r)s\frac{\partial F}{\partial s} - r\}dt$$
$$+ \{\frac{1}{\mathcal{V}}\frac{\partial \mathcal{V}}{\partial \mathcal{P}_1}\frac{d\mathcal{P}_1}{dt} + \frac{1}{\mathcal{V}}\frac{\partial \mathcal{V}}{\partial \mathcal{P}_2}\frac{d\mathcal{P}_2}{dt}\}dt$$
$$+ [\frac{1}{\mathcal{V}}\frac{\partial \mathcal{V}}{\partial s} - \frac{W_2}{FW_1}\frac{\partial F}{\partial s}]ds \qquad (8.26)$$

The instantaneous return on the portfolio is a differential stochastic process. A hedge ratio, or the proportion of dollar amounts invested in oil futures, W_2, is chosen so that the instantaneous return is non-stochastic.

$$W_2 = \frac{F}{\mathcal{V}}\frac{\partial \mathcal{V}}{\partial s}[\frac{\partial F}{\partial s}]^{-1} W_1 \qquad (8.27)$$

The expected return on the portfolio must also be zero:

$$\{\frac{1}{\mathcal{V}}[\mathcal{C}f + \frac{\partial \mathcal{V}}{\partial t} + \frac{1}{2}\sigma^2 s^2 \frac{\partial^2 \mathcal{V}}{\partial s^2}] - \frac{W_2}{FW_1}(c-r)s\frac{\partial F}{\partial s} - r\}$$
$$+ \{\frac{1}{\mathcal{V}}\frac{\partial \mathcal{V}}{\partial \mathcal{P}_1}\frac{d\mathcal{P}_1}{dt} + \frac{1}{\mathcal{V}}\frac{\partial \mathcal{V}}{\partial \mathcal{P}_2}\frac{d\mathcal{P}_2}{dt}\} = 0 \qquad (8.28)$$

Using the definition of near-state variables ($\mathcal{P}_1$, $\mathcal{P}_2$) in Section (7.3):

$$\frac{d\mathcal{P}_1}{dt} = Q_{o_1}(t,\mathcal{P}_1;\Theta_1)$$

$$\frac{d\mathcal{P}_2}{dt} = Q_{o_2}(t,\mathcal{P}_2;\mathcal{P}_1,\Theta_2) \qquad (8.29)$$

and Eqn (8.27), leads to a deterministic nonstationary second-order partial differential equation for production value in the price-time-depletion state domain (Brennan and Schwartz 1985).

$$\frac{1}{2}\sigma^2 s^2 \frac{\partial^2 \mathcal{V}}{\partial s^2} - (c-r)s\frac{\partial \mathcal{V}}{\partial s} + Q_{o_1}\frac{\partial \mathcal{V}}{\partial \mathcal{P}_1} + Q_{o_2}\frac{\partial \mathcal{V}}{\partial \mathcal{P}_2} + \frac{\partial \mathcal{V}}{\partial t} - r\mathcal{V} + \mathcal{C}f = 0 \qquad (8.30)$$

The spot oil price state is a sufficient economic statistic to determine production value. The model describes the dynamics of a continuous diffusion process for the asset value $\mathcal{V}(s,t,\mathcal{P}_1, \mathcal{P}_2;\mathcal{D})$ of a depletion strategy ($\mathcal{D}$) over a semi-infinite continuum of price states within a feasible depletion state domain.

The first-order temporal and depletion terms represents the accumulation of value along the depletion path. Production value can concentrate locally in the price domain through a transient response or operating decision. The sign of this term suggests that the diffusion process is flowing backwards in time, so that current production value responds to future events.

The first-order price term represents drift in the growth rate trend for production value. Value grows faster at higher prices, higher net convenience yield rates and lower interest rates. The zero-order term represents the time value of money. Value is continuously compounded at the risk-free interest rate. The source term generates value for the process at a rate equal to the continuous cash flow.

The second-order price term represents value dispersion over price states. Production values disperse across the price domain as the uncertainty grows about forecasting future events further ahead in time. Value will disperse more rapidly at higher prices and higher volatilities. Values concentrate as time approaches maturity of a future event and contemporaneous expectations become more certain about a forthcoming price state. This term gives the optional stage in a flexible decision process additional waiting time value. Expected payoffs may have second-order price dependencies that manifest as changes in slope at critical price-sensitive decision boundaries. If the expected payoff from a decision has second-order dependence on the price state, then the waiting value of the payoff will disperse back in time and provide additional value to earlier stages of the decision process.

In the special case where no price risk is associated with cash flows and forward prices are known with certainty ($\sigma \to 0$), the modern asset pricing model reduces to a discounted cash flow (DCF) formulation.

8.7 Action Regions

Mutually exclusive operating policies (Θ_1, Θ_2) will exhibit different remaining production values ($\mathcal{V}$) at different times (t), oil prices (s) and depletion states ($\mathcal{P}_1, \mathcal{P}_2$). The domain ($s, t, \mathcal{P}_1, \mathcal{P}_2$) is segmented into time-dependent price regions ($\mathcal{R}$) over the feasible depletion range. Primary and secondary operations will have preferred action regions ($\mathcal{R}_1, \mathcal{R}_2$) in the price-time-depletion domain (Figure 8.4). Production values within these respective regions are defined as:

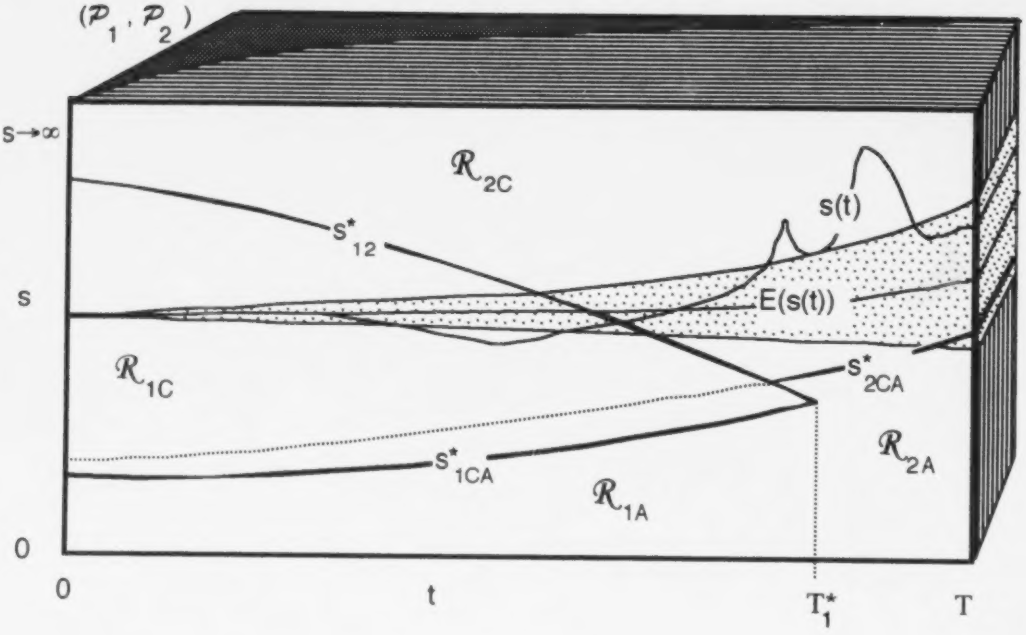
$$\begin{aligned} \mathcal{V}_1 &= \mathcal{V}_1(s,t,\mathcal{P}_1;\Theta_1) & &(s,t,\mathcal{P}_1) \in \mathcal{R}_1 \\ \mathcal{V}_2 &= \mathcal{V}_2(s,t,\mathcal{P}_2;\mathcal{P}_1,\Theta_2) & &(s,t,\mathcal{P}_2;\mathcal{P}_1) \in \mathcal{R}_2 \end{aligned} \tag{8.31}$$

The critical price boundary (s_{12}^*) that separates these actions regions will determine the price-sensitive investment decision rules for waterflood initiation.

$$s_{12}^* = s_{12}^*(t,\mathcal{P}_1) \tag{8.32}$$

Primary production value ($\mathcal{V}_1$) depends on the primary depletion state ($\mathcal{P}_1$) and primary operating policy (Θ_1). Secondary production value ($\mathcal{V}_2$) under the secondary operating policy (Θ_2) depends functionally on the secondary depletion state ($\mathcal{P}_2$) and parametrically on the originating primary depletion state ($\mathcal{P}_1$). Each operational stage (Θ_i) is further subdivided into operational modes ($\theta_{iC}, \theta_{iS}, \theta_{iA}$) for active control, pool suspension and early abandonment. Operating modes ($\theta_{iC}, \theta_{iS}, \theta_{iA}$) will have preferred action regions ($\mathcal{R}_{iC}, \mathcal{R}_{iS}, \mathcal{R}_{iA}$) in the price-time-depletion domain. The production value in these regions are defined as:

$$\begin{aligned} \mathcal{V}_{1m} &= \mathcal{V}_{1m}(s,t,\mathcal{P}_1;\theta_{1m}) & &(s,t,\mathcal{P}_1) \in \mathcal{R}_{1m} & &, m=C,S,A \\ \mathcal{V}_{2m} &= \mathcal{V}_{2m}(s,t,\mathcal{P}_2;\mathcal{P}_1,\theta_{2m}) & &(s,t,\mathcal{P}_2;\mathcal{P}_1) \in \mathcal{R}_{2m} & &, m=C,S,A \end{aligned} \tag{8.33}$$



$(\mathcal{P}_1, \mathcal{P}_2)$
$s \rightarrow \infty$
s
0
0
t
T_1^*
T
$\mathcal{R}_{2C}$
s^*_{12}
s(t)
E(s(t))
$\mathcal{R}_{1C}$
s^*_{2CA}
$\mathcal{R}_{2A}$
s^*_{1CA}
$\mathcal{R}_{1A}$

Figure 8.4: Price-Sensitive Action Regions $\mathcal{R}(\Theta_i)$ in Price-Time-Depletion

Critical price boundaries (s_{iCS}^*,s_{iCA}^*,s_{iSA}^*) separate operating regions from each other. These boundaries determine the price-sensitive decision rules for reversibly switching between active control and suspended operations (s_{iCS}^*), irreversible early abandonment from active control (s_{iCA}^*) and irreversible early abandonment from suspended operations (s_{iSA}^*).

$$\begin{aligned} s^*_{1CS} &= s^*_{1CS}(t,\mathcal{P}_1) \\ s^*_{1CA} &= s^*_{1CA}(t,\mathcal{P}_1) \\ s^*_{1SA} &= s^*_{1SA}(t,\mathcal{P}_1) \\ s^*_{2CS} &= s^*_{2CS}(t,\mathcal{P}_2;\, \mathcal{P}_1) \\ s^*_{2CA} &= s^*_{2CA}(t,\mathcal{P}_2;\, \mathcal{P}_1) \\ s^*_{2SA} &= s^*_{2SA}(t,\mathcal{P}_2;\, \mathcal{P}_1) \end{aligned} \qquad (8.34)$$

The value-maximizing operating policy for a particular recovery scheme (Θ_i) will have price-sensitive control decisions for the oil production rate (Q_i). Non-terminal operating decisions will choose between active control (θ_{iC}) and pool suspension (θ_{iS}).

$$\begin{aligned}
Q_1(s,t,\mathcal{P}_1) &= Q_1(\mathcal{P}_1;\mathcal{C}_1) && (s,t,\mathcal{P}_1)\in\mathcal{R}_{1C}\\
&= 0 && (s,t,\mathcal{P}_1)\in\mathcal{R}_{1S}\\
Q_2(s,t,\mathcal{P}_2;\mathcal{P}_1) &= Q_2(\mathcal{P}_2;\mathcal{C}_2,\mathcal{P}_1) && (s,t,\mathcal{P}_2;\mathcal{P}_1)\in\mathcal{R}_{2C}\\
&= 0 && (s,t,\mathcal{P}_2;\mathcal{P}_1)\in\mathcal{R}_{2S} \qquad (8.35)
\end{aligned}$$

Active control modes (θ_{iC}) will have a production rates determined by the design control policy:

$$\begin{aligned}
Q_{1C} &= Q_{o_1}(\mathcal{P}_1;\mathcal{C}_1)\\
Q_{2C} &= Q_{o_2}(\mathcal{P}_2;\mathcal{P}_1,\mathcal{C}_2) \qquad (8.36)
\end{aligned}$$

with associated cash flows:

$$\mathcal{C}f_{iC}(s,t,Q_{iC}) = [(1-R)\,s(t) - v_i]\,Q_{iC} - f_i \quad i=1,2 \qquad (8.37)$$

Dynamic value in active control regions ($\mathcal{R}_{iC}$, i=1,2) will be governed by:

$$\frac{1}{2}\sigma^2 s^2\frac{\partial^2\mathcal{V}_{iC}}{\partial s^2} - (c-r)s\frac{\partial\mathcal{V}_{iC}}{\partial s} + Q_{o_{iC}}\frac{\partial\mathcal{V}_{iC}}{\partial\mathcal{P}_i} + \frac{\partial\mathcal{V}_{iC}}{\partial t} - r\mathcal{V}_{iC} + \mathcal{C}f_{iC} = 0 \qquad (8.38)$$

No production will occur during pool suspension modes (θ_{iS}). Associated cash flows will only incur fixed operating costs.

$$Q_{iS} = 0 \qquad \mathcal{C}f_{iS}(t) = -f_i \qquad i=1,2 \qquad (8.39)$$

Dynamic value in suspended mode regions ($\mathcal{R}_{iS}$, i=1,2) will be governed by:

$$\frac{1}{2}\sigma^2 s^2\frac{\partial^2\mathcal{V}_{iS}}{\partial s^2} - (c-r)s\frac{\partial\mathcal{V}_{iS}}{\partial s} + \frac{\partial\mathcal{V}_{iS}}{\partial t} - r\mathcal{V}_{iS} + \mathcal{C}f_{iS} = 0 \qquad (8.40)$$

Early abandonment (θ_{iA}) is a terminating mode of operation that will establish the economic limit. Economic reserves will be exhausted and no more production will occur. The operation will have a negative value at the time of abandonment from incurring a lump sum mandatory abandonment expense (A_i). Remaining static value in early abandonment regions ($\mathcal{R}_{iA}$, i=1,2) is constant.

$$\mathcal{V}_{iA} = -A_i \tag{8.41}$$

8.8 Boundary Conditions

The critical price boundaries determine the operating and investment decision rules. These critical boundaries are found by maximizing the overall production asset value of the entire depletion strategy. Conditions at certain boundaries must be defined to determine particular asset values. Boundary conditions for production value are specified for:

- asymptotic price limit
- price origin
- terminal time
- primary and secondary depletion state feasible boundaries
- critical irreversible investment price boundary
- critical primary and secondary irreversible abandonment boundaries
- critical primary and secondary reversible suspension boundaries

An asymptotic limit will bound growth in the dynamic value of the non-terminal action regions that exist at higher prices.

$$\frac{\partial^2 \mathcal{V}_{im}}{\partial s^2} = o\left(\frac{1}{s^2}\right) \text{ as } s \rightarrow \infty \quad \text{for all } \mathcal{R}_{im} \; \{i = 1,2;\, m = C,S\} \tag{8.42}$$

The valuation model exhibits an absorbing state at zero price (s=0). The cash flow model implies that operating costs will still be incurred in the absence of production revenues. The valuation model at the price origin degenerates into a differential equation independent of the price state. Value dynamics at the price origin will depend on time and depletion states, only.

$$\begin{aligned}
&\mathcal{V}_{1m}(0,t,\mathcal{P}_1;\theta_{1m}) = \mathcal{V}_{1m}(t,\mathcal{P}_1;\theta_{1m}) && (0,t,\mathcal{P}_1) \in \mathcal{R}_{1m}, \; m=C,S \\
&\mathcal{V}_{2m}(0,t,\mathcal{P}_2;\mathcal{P}_1,\theta_{2m}) = \mathcal{V}_{2m}(t,\mathcal{P}_2;\mathcal{P}_1,\theta_{2m}) && (0,t,\mathcal{P}_2;\mathcal{P}_1) \in \mathcal{R}_{2m}, \; m=C,S
\end{aligned} \tag{8.43}$$

The primary action region ($\mathcal{R}_1$) will exist up to a time, $T_1^* \leq T$, at which point primary operations (Θ_1) will terminate, either through mandatory abandonment ($t=T$), early abandonment (θ_{iA}), or by irreversibly switching to secondary operations, (Θ_2). Operations that exist at the end of the strategic plan duration ($t=T$), will have a negative terminal value from incurring a lump sum mandatory abandonment expense (A_i).

$$\mathcal{V}_i(s,T,\mathcal{P}_1,\mathcal{P}_2;\{\Theta_i \mid \mathcal{R}_i \text{ exists at } t=T\}) = -A_i \tag{8.44}$$

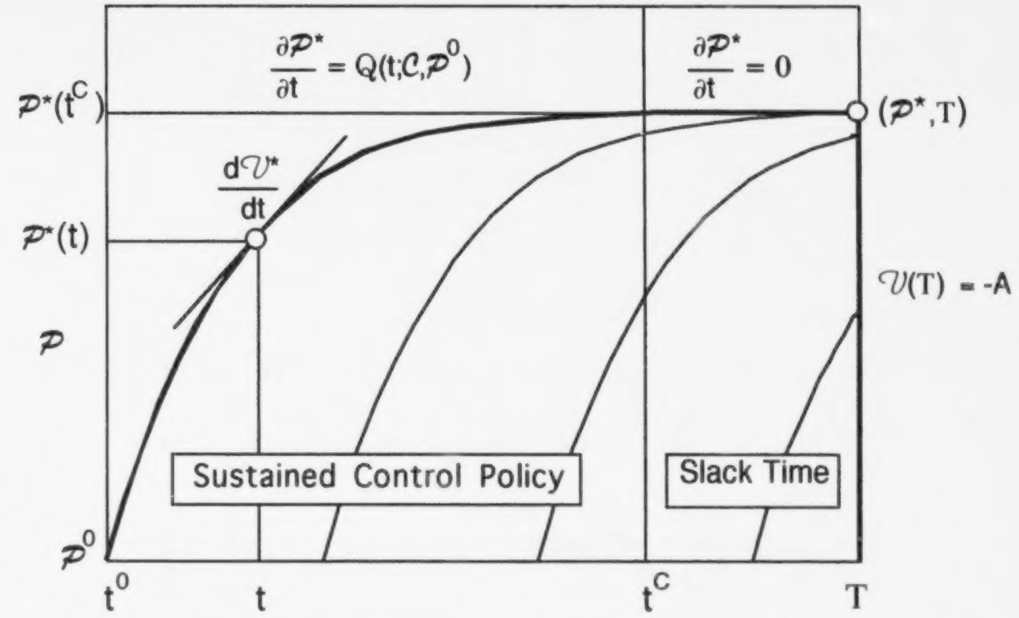


Figure 8.5: Terminal Mandatory Abandonment Boundary Condition

Action regions will have corresponding terminal conditions:

$$\begin{aligned} &\mathcal{V}_{1m}(s,T,\mathcal{P}_1;\theta_{1m}) = -A_1 && \text{if } (s,T,\mathcal{P}_1) \in \mathcal{R}_{1m} && ,\ m=C,S,A \\ &\mathcal{V}_{2m}(s,T,\mathcal{P}_2;\mathcal{P}_1,\theta_{2m}) = -A_2 && \text{if } (s,T,\mathcal{P}_2;\mathcal{P}_1) \in \mathcal{R}_{2m} && ,\ m=C,S,A \end{aligned} \tag{8.45}$$

All depletion path possibilities will be truncated at the terminal time ($t=T$). The terminal condition applies at branch endpoints of primary and secondary depletion state feasible boundaries. By definition, the feasible boundary is the maximum limit under sustained active control with no suspension possibilities. The time derivative along any active control path including the boundary path is:

$$\left.\frac{d\mathcal{V}_1}{dt}\right|_{\text{Control}} = \frac{\partial \mathcal{V}_1}{\partial t} + Q_{o_1}(\mathcal{P}_1;\, \mathcal{C}_1)\frac{\partial \mathcal{V}_1}{\partial \mathcal{P}_1}$$

$$\left.\frac{d\mathcal{V}_2}{dt}\right|_{\text{Control}} = \frac{\partial \mathcal{V}_2}{\partial t} + Q_{o_2}(\mathcal{P}_2;\, \mathcal{C}_2, \mathcal{P}_1)\frac{\partial \mathcal{V}_2}{\partial \mathcal{P}_2} \qquad (8.46)$$

The time derivative along the boundary path (*) with the terminal abandonment condition define the primary and secondary constrained depletion boundary conditions (Figure 8.5).

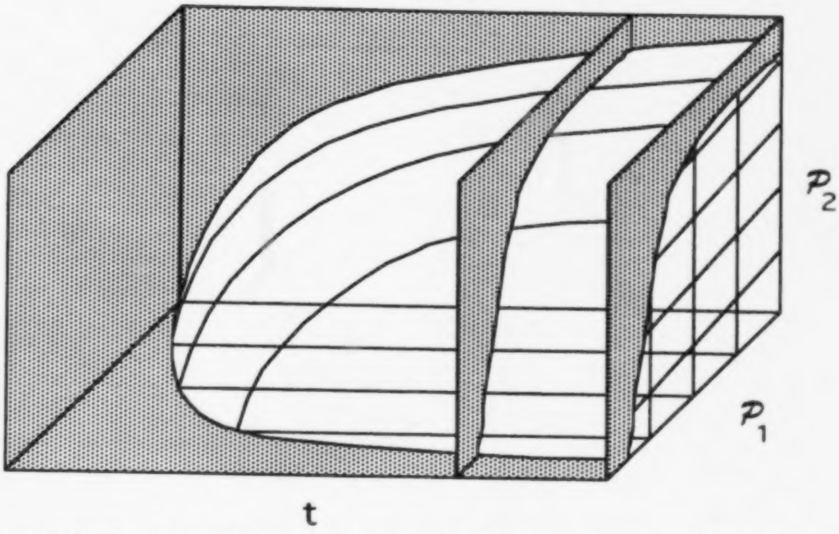
$$\left.\frac{d\mathcal{V}_1}{dt}\right|^{*} = \left.\frac{\partial \mathcal{V}_1}{\partial t}\right|^{*} + Q_{o_1}(\overset{*}{\mathcal{P}}_1(t))\left.\frac{\partial \mathcal{V}_1}{\partial \mathcal{P}_1}\right|^{*} \qquad \mathcal{V}_1(s,T)\,\Big|^{*} = -A_1$$

$$\left.\frac{d\mathcal{V}_2}{dt}\right|^{*} = \left.\frac{\partial \mathcal{V}_2}{\partial t}\right|^{*} + Q_{o_2}(\overset{*}{\mathcal{P}}_2(t;\mathcal{P}_1))\left.\frac{\partial \mathcal{V}_2}{\partial \mathcal{P}_2}\right|^{*} \qquad \mathcal{V}_2(s,T;\mathcal{P}_1)\,\Big|^{*} = -A_2$$

$$(8.47)$$

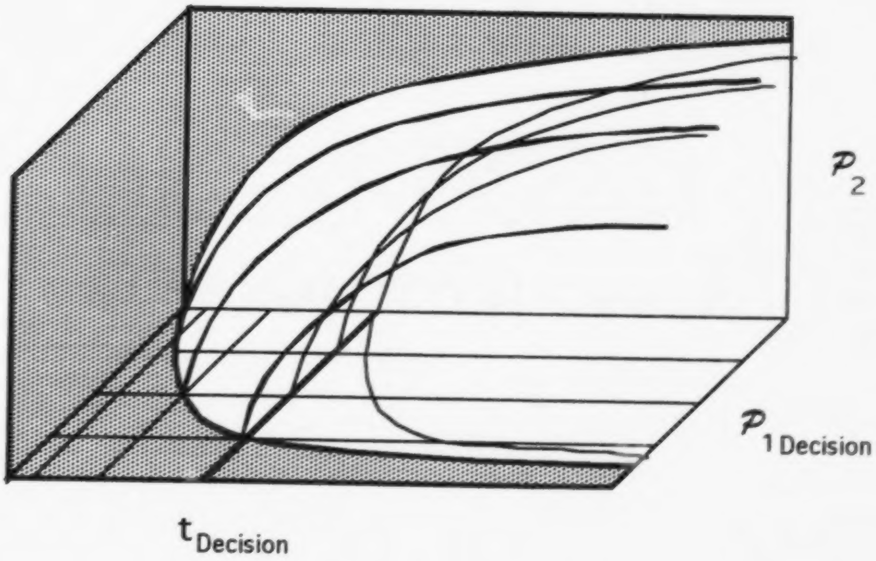
Critical price boundaries are prices at which the depletion strategy is indifferent between alternative choices. The structure of these critical boundaries will depend on how the decision-making process polls progressive performance and forecasts future expectations. Performance can be continuously polled or measured at discrete events. Discrete events can be marked by either the passage of time or by incremental production.

Continuous forecasting of path-dependent secondary recovery was deemed as virtually intractable in Section 7.1 and decision pathways were restricted to discrete investment timing options at selected primary depletion milestones (Figure 8.6). This implies that even if performance could be polled continuously, investment decisions must still be based on discrete primary production milestones that evolve continuously with time. In essence, decisions are made at discrete depletion states that are continuously tracked in time (Figure 8.7).



$\mathcal{P}_2$
$\mathcal{P}_1$
t

Figure 8.6: Feasible Depletion Space at Discrete Primary Oil Milestones



$\mathcal{P}_2$
$\mathcal{P}_{1\,Decision}$
$t_{Decision}$

Figure 8.7: Decision Times Track Discrete Depletion Milestones

This means that time interval between discrete decisions can vary as production rates change. Decision times are chosen not to exceed quarterly intervals. This also means that the secondary recovery option cannot be exercised at transitional depletion states between primary production milestones. Hence, the model investment decision process is limited to a wait-and-see approach in the depletion state-time domain (Figure 8.8).

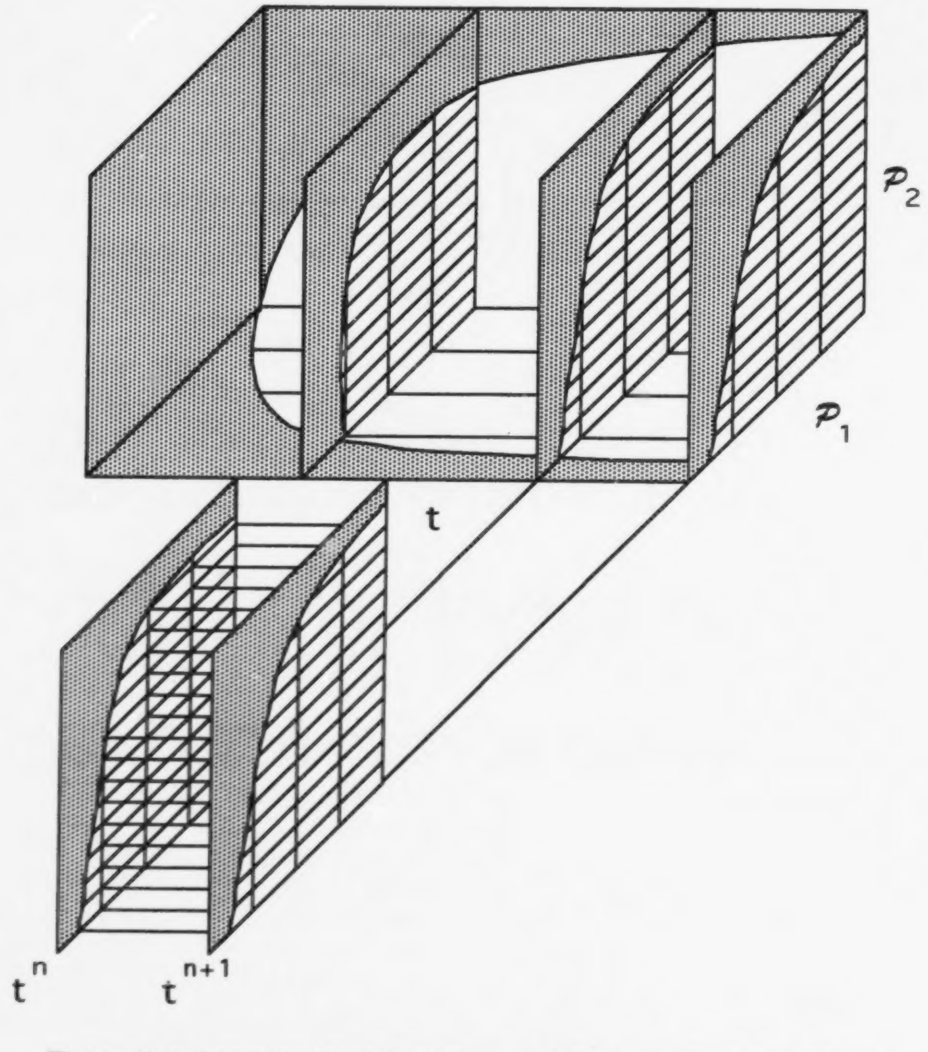


Figure 8.8: Feasible Depletion Space at Discrete Decision Times

The irreversible investment decision to choose secondary operations (Θ_2) while in primary operations (Θ_1) will depend on the relative values at the oil price and primary depletion state at the time of decision. If the expected value from initiating waterflood $\mathcal{V}_2(s,t,\mathcal{P}_2=0;\Theta_2,\mathcal{P}_1)$, net of capital investment (K_{12}) , is greater than the remaining value of the originating primary production policy $\mathcal{V}_1(s,t,\mathcal{P}_1;\Theta_1)$, then a value-maximizing investment action will shift from primary ($\mathcal{R}_1$) to secondary operations ($\mathcal{R}_2$). The remaining production value of either pathway depends on the contemporaneous reservoir state of the originating primary recovery stage in progress. This state depends on the historical depletion path followed up to the time the investment decision is made. The value of a particular alternative depends on the remaining depletion pathways and price state possibilities that follow. If the investment decision is made, then production controls applicable to the new secondary policy determine depletion pathways. If the investment decision is not made, controls for the originating primary policy remain in place. The irreversible, mutually-exclusive investment timing decision will not affect the remaining production values distinct to the respective actions. This implies that the critical price can be determined with certainty. The discrete formulation ensures no dispersion in remaining production value between mutually exclusive alternatives by placing them on separate branched pathways. The expected production value at a particular point in time from cash flow streams along remaining depletion pathways in one region will not distort the expected production value from the other.

$$\begin{gathered}\mathcal{V}_1(s=s^*_{12}, t, \mathcal{P}_1;\Theta_1) = \mathcal{V}_2(s=s^*_{12}, t, \mathcal{P}_2=0;\Theta_2, \mathcal{P}_1) - K_{12} \\ \text{where } s^*_{12}(t, \mathcal{P}_1) = \mathcal{R}_1 \cap \mathcal{R}_2\end{gathered} \tag{8.48}$$

The payoff ($\Delta\mathcal{V}_{12}$) from the waterflood investment option will be the value added from secondary recovery:

$$\Delta\mathcal{V}_{12} = \max\,[0, \mathcal{V}_2(s,t,\mathcal{P}_2=0;\mathcal{P}_1,\Theta_2) - K_{12} - \mathcal{V}_1(s,t,\mathcal{P}_1;\Theta_1)] \tag{8.49}$$

The payoff is a function of the contemporaneous spot price at decision time. The payoff increases as waterflood value, net of the capital investment, rises above the primary production value. Investment action will only proceed if the net payoff is positive and value can be added by waterflood.

$$\begin{aligned}\mathcal{V}_2(s,t,\mathcal{P}_2=0;\mathcal{P}_1,\Theta_2) - K_{12} &> \mathcal{V}_1(s,t,\mathcal{P}_1;\Theta_1) \;\rightarrow\; \{(s,t,\mathcal{P}_1,\mathcal{P}_2) \in \mathcal{R}_2\} \\ \mathcal{V}_2(s,t,\mathcal{P}_2=0;\mathcal{P}_1,\Theta_2) - K_{12} &\le \mathcal{V}_1(s,t,\mathcal{P}_1;\Theta_1) \;\rightarrow\; \{(s,t,\mathcal{P}_1,\mathcal{P}_2) \in \mathcal{R}_1\}\end{aligned} \tag{8.50}$$

The price boundary between regions is the critical investment price (s_{12}^*) at which the payoff is indifferent to either alternative. Primary and secondary action regions will have nested value-maximizing sub-regions for the three mutually-exclusive operational modes of active control (C), pooled suspension (S) and early abandonment (A). Critical price boundaries reflect indifference between alternative choices. The three-way choice between two reversible modes (C,S) and one terminal mode (A) leads to three nested critical price boundaries: C-S, C-A and S-A.

$$
\begin{array}{ll}
\mathcal{V}_{1C}(s^*_{1CS},t,\mathcal{P}_1) = \mathcal{V}_{1S}(s^*_{1CS},t,\mathcal{P}_1) & s^*_{1CS}(t,\mathcal{P}_1) = \mathcal{R}_{1C} \cap \mathcal{R}_{1S} \\
\mathcal{V}_{1C}(s^*_{1CA},t,\mathcal{P}_1) = -A_1 & s^*_{1CA}(t,\mathcal{P}_1) = \mathcal{R}_{1C} \cap \mathcal{R}_{1A} \\
\mathcal{V}_{1S}(s^*_{1SA},t,\mathcal{P}_1) = -A_1 & s^*_{1SA}(t,\mathcal{P}_1) = \mathcal{R}_{1S} \cap \mathcal{R}_{1A} \\
\mathcal{V}_{2C}(s^*_{2CS},t,\mathcal{P}_2;\mathcal{P}_1) = \mathcal{V}_{2S}(s^*_{2CS},t,\mathcal{P}_2;\mathcal{P}_1) & s^*_{2CS}(t,\mathcal{P}_2;\mathcal{P}_1) = \mathcal{R}_{2C} \cap \mathcal{R}_{2S} \\
\mathcal{V}_{2C}(s^*_{2CA},t,\mathcal{P}_2;\mathcal{P}_1) = -A_2 & s^*_{2CA}(t,\mathcal{P}_2;\mathcal{P}_1) = \mathcal{R}_{2C} \cap \mathcal{R}_{2A} \\
\mathcal{V}_{2S}(s^*_{2SA},t,\mathcal{P}_2;\mathcal{P}_1) = -A_2 & s^*_{2SA}(t,\mathcal{P}_2;\mathcal{P}_1) = \mathcal{R}_{2S} \cap \mathcal{R}_{2A}
\end{array}
\tag{8.51}
$$

Action sub-regions are chosen to maximize value over remaining decision pathways that stem from contemporaneous operation under one of the three alternative operating modes. Remaining primary value is,

$$\mathcal{V}_1(s,t,\mathcal{P}_1) = \max\{\mathcal{V}_{1C}(s,t,\mathcal{P}_1), \mathcal{V}_{1S}(s,t,\mathcal{P}_1), -A_1\} \tag{8.52}$$

with nested primary operating action regions:

$$
\left.
\begin{array}{lll}
\Theta_1(s,t,\mathcal{P}_1) & = C & \text{if } \mathcal{V}_1(s,t,\mathcal{P}_1) = \mathcal{V}_{1C}(s,t,\mathcal{P}_1) \\
 & = S & \text{if } \mathcal{V}_1(s,t,\mathcal{P}_1) = \mathcal{V}_{1S}(s,t,\mathcal{P}_1) \\
 & = A & \text{if } \mathcal{V}_1(s,t,\mathcal{P}_1) = -A_1
\end{array}
\right]
\tag{8.53}
$$

Remaining secondary value is,

$$\mathcal{V}_2(s,t,\mathcal{P}_2;\mathcal{P}_1) = \max\{\mathcal{V}_{2C}(s,t,\mathcal{P}_2;\mathcal{P}_1), \mathcal{V}_{2S}(s,t,\mathcal{P}_2;\mathcal{P}_1), -A_2\} \tag{8.54}$$

with nested secondary operating action regions:

$$\left.\begin{aligned} \Theta_2(s,t,\mathcal{P}_2;\mathcal{P}_1) &= C \quad \text{if } \mathcal{V}_2(s,t,\mathcal{P}_2;\mathcal{P}_1) = \mathcal{V}_{2C}(s,t,\mathcal{P}_2;\mathcal{P}_1) \\ &= S \quad \text{if } \mathcal{V}_2(s,t,\mathcal{P}_2;\mathcal{P}_1) = \mathcal{V}_{2S}(s,t,\mathcal{P}_2;\mathcal{P}_1) \\ &= A \quad \text{if } \mathcal{V}_2(s,t,\mathcal{P}_2;\mathcal{P}_1) = -A_2 \end{aligned}\right] \tag{8.55}$$

8.9 Decision Model Summary

The mathematical decision model for maximizing the modelled economic value ($\mathcal{V}$) of remaining operating alternatives over a strategic window is summarized below:

- Depletion Strategy Objective

$$\max \mathcal{V}(s,t,\mathcal{P}_1,\mathcal{P}_2;\mathcal{D})$$

$$s \geq 0$$

$$0 \leq t \leq T$$

$$0 \leq \mathcal{P}_1 \leq \mathcal{P}_1^*(t)$$

$$0 \leq \mathcal{P}_2 \leq \mathcal{P}_2^*(t;\mathcal{P}_1)$$

- Primary and Secondary Segmentation

$$\begin{aligned} \mathcal{V}(s,t,\mathcal{P}_1,\mathcal{P}_2;\mathcal{D}) &= \mathcal{V}_1(s,t,\mathcal{P}_1;\Theta_1) && \text{if } (s,t,\mathcal{P}_1) \in \mathcal{R}_1 \\ &= \mathcal{V}_2(s,t,\mathcal{P}_2;\Theta_2,\mathcal{P}_1) && \text{if } (s,t,\mathcal{P}_2;\mathcal{P}_1) \in \mathcal{R}_2 \end{aligned}$$

$$\begin{aligned} \mathcal{V}_1(s,t,\mathcal{P}_1;\Theta_1) &= \mathcal{V}_{1C}(s,t,\mathcal{P}_1;\theta_{1C}) && \text{if } (s,t,\mathcal{P}_1) \in \mathcal{R}_{1C} \\ &= \mathcal{V}_{1S}(s,t,\mathcal{P}_1;\theta_{1S}) && \text{if } (s,t,\mathcal{P}_1) \in \mathcal{R}_{1S} \\ &= \mathcal{V}_{1A}(s,t,\mathcal{P}_1;\theta_{1A}) && \text{if } (s,t,\mathcal{P}_1) \in \mathcal{R}_{1A} \end{aligned}$$

$$\begin{aligned} \mathcal{V}_2(s,t,\mathcal{P}_2;\Theta_2,\mathcal{P}_1) &= \mathcal{V}_{2C}(s,t,\mathcal{P}_2;\theta_{2C},\mathcal{P}_1) && \text{if } (s,t,\mathcal{P}_2;\mathcal{P}_1) \in \mathcal{R}_{2C} \\ &= \mathcal{V}_{2S}(s,t,\mathcal{P}_2;\theta_{2S},\mathcal{P}_1) && \text{if } (s,t,\mathcal{P}_2;\mathcal{P}_1) \in \mathcal{R}_{2S} \\ &= \mathcal{V}_{2A}(s,t,\mathcal{P}_2;\theta_{2A},\mathcal{P}_1) && \text{if } (s,t,\mathcal{P}_2;\mathcal{P}_1) \in \mathcal{R}_{2A} \end{aligned}$$

- Production Control Policy Subject to Regulatory Constraints

$$Q_{1C} = Q_{o_1}(\mathcal{P}_1; \mathcal{C}_1)$$

$$Q_{2C} = Q_{o_2}(\mathcal{P}_2; \mathcal{P}_1, \mathcal{C}_2)$$

- Before Tax Cash Flow Model (i=1,2)

$$\mathcal{Cf}_{iC}(s,t,Q_{iC}) = [(1-R)\,s(t) - v_i]\,Q_{iC} - f_i$$
$$\mathcal{Cf}_{iS}(t) = -f_i$$

- Active Control Mode (C) Dynamic Value (i=1,2)

$$\frac{1}{2}\sigma^2 s^2 \frac{\partial^2 \mathcal{V}_{iC}}{\partial s^2} - (c-r)s\frac{\partial \mathcal{V}_{iC}}{\partial s} + Q_{o_{iC}}\frac{\partial \mathcal{V}_{iC}}{\partial \mathcal{P}_i} + \frac{\partial \mathcal{V}_{iC}}{\partial t} - r\mathcal{V}_{iC} + \mathcal{Cf}_{iC} = 0$$

- Pooled Suspension Mode (S) Dynamic Value (i=1,2)

$$\frac{1}{2}\sigma^2 s^2 \frac{\partial^2 \mathcal{V}_{iS}}{\partial s^2} - (c-r)s\frac{\partial \mathcal{V}_{iS}}{\partial s} + \frac{\partial \mathcal{V}_{iS}}{\partial t} - r\mathcal{V}_{iS} + \mathcal{Cf}_{iS} = 0$$

- Early Abandonment Mode (A) Static Value (i=1,2)

$$\mathcal{V}_{iA} = -A_i$$

- Price Origin Boundary Condition (m=C,S)

$$\mathcal{V}_{1m}(0,t,\mathcal{P}_1; \theta_{1m}) = \mathcal{V}_{1m}(t,\mathcal{P}_1; \theta_{1m})$$
$$\mathcal{V}_{2m}(0,t,\mathcal{P}_2; \mathcal{P}_1, \theta_{2m}) = \mathcal{V}_{2m}(t,\mathcal{P}_2; \mathcal{P}_1, \theta_{2m})$$

- Asymptotic Price Boundary Condition (i=1,2; m=C,S)

$$\frac{\partial^2 \mathcal{V}_{im}}{\partial s^2} = O\left(\frac{1}{s^2}\right) \text{ as } s \to \infty$$

- Terminal Boundary Condition (m=C,S)

$$\mathcal{V}_{1m}(s,t=T,\ \mathcal{P}_1) = -A_1$$
$$\mathcal{V}_{2m}(s,t=T,\ \mathcal{P}_2;\ \mathcal{P}_1) = -A_2$$

- Depletion Boundary Constraint

$$\left.\frac{d\mathcal{V}_1}{dt}\right|^{*} = \left.\frac{\partial\mathcal{V}_1}{\partial t}\right|^{*} + Q_{o_1}(\mathcal{P}_1^{*}(t))\left.\frac{\partial\mathcal{V}_1}{\partial\mathcal{P}_1}\right|^{*}$$
$$\left.\frac{d\mathcal{V}_2}{dt}\right|^{*} = \left.\frac{\partial\mathcal{V}_2}{\partial t}\right|^{*} + Q_{o_2}(\mathcal{P}_2^{*}(t;\mathcal{P}_1))\left.\frac{\partial\mathcal{V}_2}{\partial\mathcal{P}_2}\right|^{*}$$

- Nested Critical Operating Price Boundary Conditions

$$\begin{array}{ll}
\mathcal{V}_{1C}(s^{*}_{1CS},t,\mathcal{P}_1) = \mathcal{V}_{1S}(s^{*}_{1CS},t,\mathcal{P}_1) & s^{*}_{1CS}(t,\mathcal{P}_1) = \mathcal{R}_{1C}\cap\mathcal{R}_{1S} \\
\mathcal{V}_{1C}(s^{*}_{1CA},t,\mathcal{P}_1) = -A_1 & s^{*}_{1CA}(t,\mathcal{P}_1) = \mathcal{R}_{1C}\cap\mathcal{R}_{1A} \\
\mathcal{V}_{1S}(s^{*}_{1SA},t,\mathcal{P}_1) = -A_1 & s^{*}_{1SA}(t,\mathcal{P}_1) = \mathcal{R}_{1S}\cap\mathcal{R}_{1A} \\
\mathcal{V}_{2C}(s^{*}_{2CS},t,\mathcal{P}_2;\ \mathcal{P}_1) = \mathcal{V}_{2S}(s^{*}_{2CS},t,\mathcal{P}_2;\ \mathcal{P}_1) & s^{*}_{2CS}(t,\mathcal{P}_2;\ \mathcal{P}_1) = \mathcal{R}_{2C}\cap\mathcal{R}_{2S} \\
\mathcal{V}_{2C}(s^{*}_{2CA},t,\mathcal{P}_2;\ \mathcal{P}_1) = -A_2 & s^{*}_{2CA}(t,\mathcal{P}_2;\ \mathcal{P}_1) = \mathcal{R}_{2C}\cap\mathcal{R}_{2A} \\
\mathcal{V}_{2S}(s^{*}_{2SA},t,\mathcal{P}_2;\ \mathcal{P}_1) = -A_2 & s^{*}_{2SA}(t,\mathcal{P}_2;\ \mathcal{P}_1) = \mathcal{R}_{2S}\cap\mathcal{R}_{2A}
\end{array}$$

- Nested Primary (i=1) Operating Decisions

$$\mathcal{V}_1(s,t,\mathcal{P}_1;\Theta_1) = \max\left[\mathcal{V}_{1C}(s,t,\mathcal{P}_1;\theta_{1C}),\mathcal{V}_{1S}(s,t,\mathcal{P}_1;\theta_{1S}),-A_1\right]$$
$$s\geq 0;\ (t,\mathcal{P}_1)\in\{(t,\mathcal{P}_1)_{\text{Decision}}\,|\,0\leq t\leq T;\ 0\leq\mathcal{P}_1\leq\mathcal{P}_1^{*}(t)\}$$
$$\left.\begin{array}{lll}
\Theta_1(s,t,\mathcal{P}_1) & = C & \text{if } \mathcal{V}_1(s,t,\mathcal{P}_1) = \mathcal{V}_{1C}(s,t,\mathcal{P}_1) \\
 & = S & \text{if } \mathcal{V}_1(s,t,\mathcal{P}_1) = \mathcal{V}_{1S}(s,t,\mathcal{P}_1) \\
 & = A & \text{if } \mathcal{V}_1(s,t,\mathcal{P}_1) = -A_1
\end{array}\right]$$

- Nested Secondary (i=2) Operating Decisions

$$\mathcal{V}_2(s,t,\mathcal{P}_2;\Theta_2,\mathcal{P}_1) = \max\left[\mathcal{V}_{2C}(s,t,\mathcal{P}_2;\Theta_2,\mathcal{P}_1),\mathcal{V}_{2S}(s,t,\mathcal{P}_2;\Theta_2,\mathcal{P}_1),-A_2\right]$$

$$s \geq 0\ ;\ (t,\mathcal{P}_1) \in \{(t,\mathcal{P}_1)_{Decision} \,|\, 0 \leq t \leq T\ ;\ 0 \leq \mathcal{P}_1 \leq \mathcal{P}_1^*(t)\}$$

$$\mathcal{P}_2 \in \{(\mathcal{P}_2)_{Decision} \,|\, 0 \leq \mathcal{P}_2 \leq \mathcal{P}_2^*(t;\mathcal{P}_1)\}$$

$$\left.\begin{aligned} \Theta_2(s,t,\mathcal{P}_2;\mathcal{P}_1) &= C \quad \text{if } \mathcal{V}_2(s,t,\mathcal{P}_2;\mathcal{P}_1) = \mathcal{V}_{2C}(s,t,\mathcal{P}_2;\mathcal{P}_1) \\ &= S \quad \text{if } \mathcal{V}_2(s,t,\mathcal{P}_2;\mathcal{P}_1) = \mathcal{V}_{2S}(s,t,\mathcal{P}_2;\mathcal{P}_1) \\ &= A \quad \text{if } \mathcal{V}_2(s,t,\mathcal{P}_2;\mathcal{P}_1) = -A_2 \end{aligned}\right]$$

- Critical Investment Price Boundary Condition

$$\mathcal{V}_1(s=s_{12}^*,t,\mathcal{P}_1;\Theta_1) = \mathcal{V}_2(s=s_{12}^*,t,\mathcal{P}_2=0;\Theta_2,\mathcal{P}_1) - K_{12}$$

$$\text{where } s_{12}^*(t,\mathcal{P}_1) = \mathcal{R}_1 \cap \mathcal{R}_2$$

- Investment Timing Decision

$$\max\left[\mathcal{V}_1(s,t,\mathcal{P}_1;\Theta_1),\mathcal{V}_2(s,t,\mathcal{P}_2=0;\Theta_2,\mathcal{P}_1)-K_{12}\right]$$

$$s \geq 0\ ;\ (t,\mathcal{P}_1) \in \{(t,\mathcal{P}_1)_{Decision} \,|\, 0 \leq t \leq T\ ;\ 0 \leq \mathcal{P}_1 \leq \mathcal{P}_1^*(t)\}$$

$$\rightarrow \max \mathcal{V}(s,t,\mathcal{P}_1,\mathcal{P}_2;\mathcal{D})$$

Chapter 9: Depletion Strategy

9.1 Dynamic Programming

The effect of any initial choice of allowable actions in $\mathcal{D}$ will convert the reservoir state $(\mathcal{P}_{1,}\ \mathcal{P}_2)^n$ at time (t^n), over the time interval $[t^n,t^n+\Delta t]$, into a new state $(\mathcal{P}_{1,}\ \mathcal{P}_2)^{n+1}$ at time $(t^n+\Delta t)$, by way of the differential equations governing the reservoir dynamic response under the control policy that satisfies regulatory constraints. Over the same period, the price state (s^n) will change to (s^{n+1}), by way of the exogenous continuous random walk model for volatile future price movements. Whatever the initial choice of action is over $[t^n,t^n+\Delta t]$, an optimization problem of precisely the same form as the original will apply over the remaining interval $[t^n+\Delta t,T]$, with the only difference being that $(s,\mathcal{P}_{1,}\ \mathcal{P}_2)^n$ is replaced by $(s,\mathcal{P}_{1,}\ \mathcal{P}_2)^{n+1}$.

$$\max \mathcal{V}(s,t,\mathcal{P}_{1,}\ \mathcal{P}_2;\mathcal{D}) \tag{9.1}$$

The principle of optimality (Bellman, 1957) states:

"An optimal policy has the property that whatever the initial state and initial decision are, the remaining decisions must constitute an optimal policy with regard to the state resulting from the first decision."

For the multi-step policy to be optimal, it must be optimal at each step. A numerical algorithm based on finite-difference dynamic programming methods with critical boundary tracking procedures is presented in Appendix A2. The dynamic programming procedure marches from known terminal states, back in time and depletion, to the initial decision point. Price-sensitive value-maximizing actions are tracked in the feasible depletion space at discrete decision times.

9.2 Model Results

The depletion strategy for the optional waterflood design proposed for Chedderville Viking "A" was constructed with decision times not exceeding quarterly intervals at discrete primary and secondary depletion state cumulative oil production milestones. The expected median of future oil prices are the same as the current oil price ($20/bbl). The annual price volatility is set at 23.3%. The real risk-free interest rate is held constant at 3% and the convenience yield rate at 5%. Table 9.1(a)-(j) tabulates the schedules of price-sensitive decision rules for waterflood investment action while under primary operations. These schedules are listed for future times, measured in years, from the start of the strategic depletion plan (Oct-1-95) which is one year in the future from the current time (Oct-1-94). Action regions and remaining project value are tabulated as functions of the feasible primary depletion state and contemporaneous spot oil price at selected times. Figure 9.1 plots the remaining value at selected times as functions of the primary depletion state and spot oil price. Remaining values decrease with time and depletion state and increase with oil price.

Table 9.1(a) indicates that the value-maximizing action at the beginning of the plan (Oct-1-95) is to invest in the waterflood if oil prices are above $13/bbl and to abandon operations if oil prices drop below $6/bbl. The expected net contemporaneous value of the waterflood is $40.7 million for a $32.4 million capital outlay on Oct-1-95 if the contemporaneous oil price is $20/bbl. The sustained primary depletion boundary path develops over the 12 year primary production life cycle (Tables 9.1(a)-(d)). Waterflood investment decisions are made at discrete primary production milestones and primary operations are assumed to prevail over transitionary depletion states marked by the leading edge of the primary depletion path ($\mathcal{P}_1=\mathcal{P}_1^*$). The critical investment price remains steady at $13/bbl over the first 4 years (Table 9.1(d)) and rises slowly to $15/bbl by the end of feasible waterflood window ($\mathcal{P}_1$=800 MSTB) over 12 years of primary production (Table 9.1(f)). The critical investment price increases steadily over remaining futures times ($t > 12$ years) as the proposed 20 year waterflood duration is truncated short at the terminal 32 year strategic window (Tables 9.1(f)-(j)). If primary operations are in progress at the end of 24 years, then the secondary option with 8 years of waterflood is still the better choice at the expected median oil price of $20/bbl (Table 9.1(i)). After 28 years, the secondary option with less than 4 years of waterflood cannot deliver the additional value to warrant investment at $20/bbl (Table 9.1(j)). The transient effects of the finite duration depletion strategy become pronounced after 24 years with returns diminishing as waterfloods are truncated (Figure 9.1).

The depletion strategy has price-sensitive decision rules for secondary operations that stem from waterflood initiation at discrete primary depletion states. The full package of 32 annual decision rules for all primary launch points (≤9) constitutes over 200 individual tables. Only selected times for the initial primary launch point ($\mathcal{P}_1$=0) will be shown here, since this is the one most likely to be implemented from the start. Net secondary values at primary launch points that exceed the critical investment floor are explicit in the primary schedules. Table 9.2(a)-(i) tabulates the schedules of price-sensitive decision rules for secondary operations if waterflood is initiated from the current primary depletion state ($\mathcal{P}_1=0$). Action regions and remaining gross secondary value are tabulated as functions of the feasible secondary depletion state and contemporaneous spot oil price at selected times. Figure 9.2 plots the remaining secondary value at selected times as functions of the secondary depletion state and spot oil price. Remaining values decrease with time and depletion state and increase with oil price. Table 9.2(a) indicates that the current economic limit abandonment price is about $5/bbl. Pooled suspension is sub-optimal so that no price regions appear. Remaining secondary value decreases rapidly with increasing cumulative secondary production (Figure 9.2).The same transient effects of the finite duration depletion strategy become pronounced after 24 years with returns diminishing as waterfloods are truncated. It should be noted that the investment regions in the primary schedules are only based on starting secondary values as indicated by the trailing edge of individual dune-like profiles. The economic limit abandonment price increases with secondary depletion. The economic limit is above the expected median oil price ($20/bbl) before the end of the planned waterflood life ($\mathcal{P}_2=9500$ MSTB) as shown in Table 9.2(g). This implies that the planned waterflood may be cut short by a couple of years and abandoned early if the contemporaneous oil price is below $21/bbl at t=18 years.

Primary values ($\mathcal{V}_1$) include long positions in a waterflood call option and an early abandonment put option, while secondary values ($\mathcal{V}_2$) include only the put option on early abandonment. The dune-like profiles represented in Figures 9.1 and 9.2 are extensions of the hockey-stick payoff functions in the price domain that are familiar to financial options. The downside risk in both primary and secondary operations are hedged using a protective put strategy (Hull 1991) which is the combination of a long position in the production asset and a long position in an early abandonment American put option. The put option is only exercised if the payoff from early abandonment is greater than the payoff from continued operations. The waterflood call option is only exercised if the payoff from waterflood is greater than the payoff from continued primary operations.

The price at which the early abandonment put option is exercised is the price that determines the economic limit of the operation. Table 9.3 tabulates the primary economic limit annually for different stages of primary depletion. Figure 9.3 plots these critical abandonment prices as functions of time and primary depletion state. The primary economic limit increases with depletion state. The economic limit for sustained primary production over the full strategic window is below the expected median oil price ($20/bbl). Table 9.4 tabulates the secondary economic limit annually for different stages of secondary depletion for all admissible primary launch states. The evolution of the feasible depletion boundary can be seen over consecutive years. Highlighted cells that have no numeric value represent out-of-range prices. It should be noted that leading cells in the depletion front do not necessarily coincide with the depletion partition and may represent partial intervals. Economic limits generally increase with increasing depletion. However, secondary cash flows are generally lower over an initial waterflood period which also diminish with waterflood timing delay. The incremental value over the initial period may be subject to net cash outflow before benefits can be realized further down the depletion path. The economic limit will therefore be higher initially to reflect lower secondary output and potential decreases in incremental value. The general trend picks up after initially low output. Transient effects become apparent only in the last two years of the strategic plan. Figure 9.4 plots critical abandonment prices as functions of time and secondary depletion state for the initial primary launch point ($\mathcal{P}_1=0$). The economic waterflood life may be cut short by a couple of years if the oil price stays about the expected median oil price ($20/bbl).

The pooled suspension operating mode does not exist in this depletion strategy. This implies that the active control and early abandonment regions totally mask the sub-optimal suspended pool operating choice. The compound interest on the abandonment expense is much less than the annuity of fixed costs. Fixed costs would have to come down an order of magnitude before the option to suspend production becomes more cost-effective than early abandonment.

9.3 Recommended Action

The recommended action for Chedderville Viking "A" is facilitate a detailed waterflood design based on the proposed model and implement a revised depletion strategy as soon as possible. Accelerated pilot studies may be needed to verify model predictions for waterflood response. The strategic plan for remaining production possibilities should be revised periodically as new information emerges from continued production.

9.4 Model Limitations

The decision model is based on a probability structure of macro-economic scenarios that assume a random walk in volatile price movements. This assumption is reasonable in the absence of oil price shocks. Reversion models should be used to describe price behaviour for scenarios that include these events.

t=0 yrs	Primary Secondary Abandon
Oil Price	Cumulative Primary Oil $\mathcal{P}_1$ (MSTB)
s ($/bbl)	0
$0	-$1.0
$1	-$1.0
$2	-$1.0
$3	-$1.0
$4	-$1.0
$5	-$1.0
$6	-$1.0
$7	-$0.9
$8	-$0.9
$9	-$0.7
$10	-$0.6
$11	-$0.4
$12	-$0.1
$13	$3.7
$14	$8.9
$15	$14.2
$16	$19.5
$17	$24.7
$18	$30.0
$19	$35.3
$20	$40.7
$21	$46.1
$22	$51.5
$23	$56.9
$24	$62.4
$25	$67.8
$26	$73.2
$27	$78.7
$28	$84.1
$29	$89.6
$30	$95.1
$31	$100.6
$32	$106.0
$33	$111.6
$34	$117.1
$35	$122.6
$36	$128.1
$37	$133.6
$38	$139.1
$39	$144.6
$40	$150.1

Table 9.1(a): Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=0)

t=1 yrs	Primary	Secondary	Abandon
Oil Price	Cumulative Primary Oi $\mathcal{P}_1$ (MSTB)		
s ($/bbl)	0	100	149
$0	-$1.0	-$1.0	-$1.0
$1	-$1.0	-$1.0	-$1.0
$2	-$1.0	-$1.0	-$1.0
$3	-$1.0	-$1.0	-$1.0
$4	-$1.0	-$1.0	-$1.0
$5	-$1.0	-$1.0	-$1.0
$6	-$1.0	-$1.0	-$1.0
$7	-$1.0	-$1.0	-$1.0
$8	-$0.9	-$1.0	-$1.0
$9	-$0.7	-$0.9	-$1.0
$10	-$0.6	-$0.8	-$0.9
$11	-$0.4	-$0.7	-$0.8
$12	-$0.1	-$0.5	-$0.6
$13	$3.3	$2.5	$1.2
$14	$8.5	$7.7	$6.1
$15	$13.8	$12.9	$11.0
$16	$19.0	$18.1	$16.0
$17	$24.2	$23.3	$21.1
$18	$29.4	$28.5	$26.2
$19	$34.7	$33.7	$31.3
$20	$40.0	$38.9	$36.3
$21	$45.4	$44.2	$41.4
$22	$50.8	$49.5	$46.5
$23	$56.1	$54.9	$51.6
$24	$61.5	$60.2	$56.7
$25	$66.9	$65.6	$61.8
$26	$72.3	$71.0	$67.0
$27	$77.7	$76.3	$72.1
$28	$83.1	$81.7	$77.3
$29	$88.6	$87.1	$82.5
$30	$94.0	$92.4	$87.7
$31	$99.4	$97.8	$92.9
$32	$104.9	$103.2	$98.1
$33	$110.4	$108.5	$103.3
$34	$115.8	$113.9	$108.5
$35	$121.3	$119.3	$113.7
$36	$126.7	$124.7	$119.0
$37	$132.2	$130.1	$124.2
$38	$137.7	$135.4	$129.4
$39	$143.1	$140.8	$134.6
$40	$148.6	$146.2	$139.9

Table 9.1(b): Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=1 yr)

t=2 yrs	Primary	Secondary	Abandon	
Oil Price s ($/bbl)	Cumulative Primary Oil $\mathcal{P}_1$ (MSTB)			
	0	100	200	250
$0	-$1.0	-$1.0	-$1.0	-$1.0
$1	-$1.0	-$1.0	-$1.0	-$1.0
$2	-$1.0	-$1.0	-$1.0	-$1.0
$3	-$1.0	-$1.0	-$1.0	-$1.0
$4	-$1.0	-$1.0	-$1.0	-$1.0
$5	-$1.0	-$1.0	-$1.0	-$1.0
$6	-$1.0	-$1.0	-$1.0	-$1.0
$7	-$1.0	-$1.0	-$1.0	-$1.0
$8	-$0.9	-$1.0	-$1.0	-$1.0
$9	-$0.7	-$0.9	-$1.0	-$1.0
$10	-$0.6	-$0.8	-$1.0	-$1.0
$11	-$0.4	$0.7	-$0.9	-$0.9
$12	-$0.1	-$0.5	-$0.7	-$0.8
$13	$3.2	$2.2	$1.4	$0.1
$14	$8.4	$7.4	$6.3	$4.7
$15	$13.6	$12.5	$11.3	$9.5
$16	$18.8	$17.7	$16.4	$14.4
$17	$24.0	$22.9	$21.5	$19.2
$18	$29.3	$28.0	$26.6	$24.1
$19	$34.5	$33.2	$31.8	$29.0
$20	$39.8	$38.5	$36.9	$33.9
$21	$45.2	$43.7	$42.1	$38.8
$22	$50.5	$49.0	$47.2	$43.8
$23	$55.9	$54.3	$52.3	$48.8
$24	$61.2	$59.6	$57.5	$53.8
$25	$66.6	$64.9	$62.7	$58.8
$26	$72.0	$70.3	$67.8	$63.8
$27	$77.4	$75.6	$73.0	$68.9
$28	$82.8	$80.9	$78.3	$73.9
$29	$88.2	$86.3	$83.5	$79.0
$30	$93.6	$91.6	$88.7	$84.0
$31	$99.1	$97.0	$94.0	$89.1
$32	$104.5	$102.3	$99.3	$94.2
$33	$109.9	$107.6	$104.5	$99.2
$34	$115.4	$113.0	$109.8	$104.3
$35	$120.8	$118.3	$115.1	$109.4
$36	$126.3	$123.7	$120.4	$114.5
$37	$131.7	$129.0	$125.6	$119.6
$38	$137.2	$134.4	$130.9	$124.7
$39	$142.6	$139.7	$136.2	$129.8
$40	$148.1	$145.1	$141.4	$134.8

Table 9.1(c): Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=2 yrs)

t=4 yrs	Primary	Secondary	Abandon			
Oil Price	Cumulative Primary Oil $\mathcal{P}_1$ (MSTB)					
s ($/bbl)	0	100	200	300	400	412
$0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$1	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$2	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$3	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$4	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$5	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$6	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$7	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$8	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$9	-$0.7	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0
$10	-$0.6	-$0.8	-$1.0	-$1.0	-$1.0	-$1.0
$11	-$0.4	-$0.7	-$0.9	-$1.0	-$1.0	-$1.0
$12	-$0.1	-$0.5	-$0.8	-$0.9	-$0.9	-$0.9
$13	$3.1	$2.1	$1.0	$0.1	-$0.5	-$0.8
$14	$8.3	$7.2	$5.9	$5.0	$4.3	$1.5
$15	$13.5	$12.4	$10.9	$9.9	$9.2	$5.9
$16	$18.7	$17.5	$15.9	$14.8	$14.1	$10.3
$17	$23.9	$22.7	$21.0	$19.7	$19.0	$14.8
$18	$29.1	$27.8	$26.1	$24.7	$23.9	$19.4
$19	$34.4	$33.0	$31.2	$29.6	$28.8	$23.9
$20	$39.7	$38.2	$36.3	$34.6	$33.7	$28.6
$21	$45.0	$43.4	$41.4	$39.6	$38.6	$33.2
$22	$50.3	$48.7	$46.5	$44.7	$43.5	$37.8
$23	$55.7	$54.0	$51.6	$49.7	$48.4	$42.4
$24	$61.0	$59.3	$56.7	$54.8	$53.4	$47.1
$25	$66.4	$64.6	$61.8	$59.9	$58.4	$51.7
$26	$71.7	$69.9	$67.0	$65.0	$63.4	$56.4
$27	$77.1	$75.2	$72.1	$70.1	$68.4	$61.1
$28	$82.5	$80.5	$77.3	$75.2	$73.5	$65.8
$29	$87.9	$85.8	$82.5	$80.3	$78.6	$70.5
$30	$93.3	$91.1	$87.7	$85.4	$83.6	$75.2
$31	$98.7	$96.5	$92.9	$90.5	$88.7	$79.9
$32	$104.2	$101.8	$98.1	$95.7	$93.8	$84.7
$33	$109.6	$107.1	$103.3	$100.8	$98.9	$89.4
$34	$115.0	$112.4	$108.6	$106.0	$103.9	$94.1
$35	$120.4	$117.7	$113.8	$111.1	$109.0	$98.9
$36	$125.9	$123.1	$119.0	$116.3	$114.1	$103.6
$37	$131.3	$128.4	$124.2	$121.4	$119.2	$108.4
$38	$136.7	$133.7	$129.5	$126.6	$124.3	$113.1
$39	$142.1	$139.1	$134.7	$131.7	$129.4	$117.8
$40	$147.6	$144.4	$139.9	$136.8	$134.4	$122.6

Table 9.1(d): Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=4 yrs)

t=8 yrs	Primary	Secondary	Abandon

Oil Price s ($/bbl)	Cumulative Primary Oil $\mathcal{P}_1$ (MSTB) 0	100	200	300	400	500	600	672
$0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$1	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$2	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$3	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$4	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$5	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$6	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$7	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$8	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$9	-$0.7	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$10	-$0.6	-$0.8	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$11	-$0.4	-$0.7	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$12	-$0.1	-$0.5	-$0.8	-$0.9	-$0.9	-$1.0	-$1.0	-$1.0
$13	$3.1	$2.1	$0.9	$0.0	-$0.8	-$0.9	-$1.0	-$1.0
$14	$8.3	$7.2	$5.9	$4.8	$3.7	$2.3	$1.1	-$1.0
$15	$13.5	$12.3	$10.8	$9.7	$8.5	$6.9	$5.7	$2.2
$16	$18.7	$17.5	$15.8	$14.6	$13.4	$11.5	$10.2	$6.5
$17	$23.9	$22.6	$20.9	$19.5	$18.2	$16.2	$14.8	$10.8
$18	$29.1	$27.8	$25.9	$24.4	$23.0	$20.9	$19.3	$15.2
$19	$34.3	$32.9	$31.0	$29.3	$27.9	$25.7	$23.9	$19.5
$20	$39.6	$38.1	$36.1	$34.3	$32.7	$30.4	$28.5	$23.9
$21	$44.9	$43.4	$41.2	$39.3	$37.5	$35.2	$33.1	$28.3
$22	$50.3	$48.6	$46.3	$44.3	$42.4	$39.9	$37.7	$32.8
$23	$55.6	$53.9	$51.4	$49.3	$47.3	$44.7	$42.4	$37.2
$24	$60.9	$59.1	$56.5	$54.3	$52.2	$49.5	$47.1	$41.6
$25	$66.3	$64.4	$61.6	$59.4	$57.1	$54.3	$51.8	$46.0
$26	$71.6	$69.7	$66.7	$64.4	$62.1	$59.2	$56.5	$50.4
$27	$77.0	$75.0	$71.9	$69.5	$67.0	$64.0	$61.3	$54.9
$28	$82.4	$80.3	$77.0	$74.6	$72.0	$68.9	$66.0	$59.3
$29	$87.8	$85.6	$82.2	$79.6	$77.0	$73.7	$70.7	$63.8
$30	$93.2	$90.9	$87.4	$84.7	$81.9	$78.6	$75.5	$68.3
$31	$98.6	$96.2	$92.6	$89.8	$86.9	$83.5	$80.3	$72.8
$32	$104.0	$101.5	$97.7	$94.9	$91.9	$88.4	$85.0	$77.3
$33	$109.4	$106.8	$102.9	$100.0	$96.9	$93.2	$89.8	$81.8
$34	$114.8	$112.1	$108.1	$105.1	$101.9	$98.1	$94.6	$86.3
$35	$120.2	$117.4	$113.3	$110.2	$106.9	$103.0	$99.3	$90.8
$36	$125.6	$122.7	$118.5	$115.3	$111.9	$107.9	$104.1	$95.3
$37	$131.0	$128.0	$123.7	$120.4	$116.9	$112.8	$108.9	$99.8
$38	$136.4	$133.3	$128.9	$125.5	$121.9	$117.6	$113.7	$104.4
$39	$141.8	$138.7	$134.1	$130.6	$126.9	$122.5	$118.4	$108.9
$40	$147.2	$144.0	$139.3	$135.7	$131.9	$127.4	$123.2	$113.4

Table 9.1(e): Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=8 yrs)

t=12 yrs	Primary	Secondary	Abandon

Oil Price	Cumulative Primary Oil $\mathcal{P}_1$ (MSTB)									
s ($/bbl)	0	100	200	300	400	500	600	700	800	843
$0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$1	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$2	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$3	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$4	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$5	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$6	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$7	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$8	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$9	-$0.7	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$10	-$0.6	-$0.8	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$11	-$0.4	-$0.7	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$12	-$0.1	-$0.5	-$0.8	-$0.9	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$13	$3.1	$2.1	$0.9	$0.0	-$0.8	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0
$14	$8.3	$7.2	$5.9	$4.8	$3.7	$2.2	$0.8	-$1.0	-$1.0	-$1.0
$15	$13.5	$12.3	$10.8	$9.7	$8.5	$6.8	$5.3	$2.3	-$0.4	-$1.0
$16	$18.6	$17.4	$15.8	$14.6	$13.3	$11.4	$9.9	$6.6	$3.7	-$1.0
$17	$23.8	$22.6	$20.8	$19.4	$18.1	$16.1	$14.4	$11.0	$7.7	-$1.0
$18	$29.1	$27.7	$25.9	$24.3	$23.0	$20.8	$18.9	$15.4	$11.9	-$1.0
$19	$34.3	$32.9	$31.0	$29.3	$27.8	$25.5	$23.5	$19.7	$16.0	-$1.0
$20	$39.6	$38.1	$36.0	$34.2	$32.6	$30.2	$28.0	$24.1	$20.1	-$1.0
$21	$44.9	$43.3	$41.1	$39.2	$37.4	$35.0	$32.6	$28.5	$24.3	-$1.0
$22	$50.2	$48.5	$46.2	$44.2	$42.3	$39.7	$37.2	$33.0	$28.5	-$1.0
$23	$55.5	$53.7	$51.3	$49.2	$47.1	$44.5	$41.8	$37.4	$32.6	-$1.0
$24	$60.8	$59.0	$56.3	$54.2	$52.0	$49.2	$46.4	$41.8	$36.8	-$1.0
$25	$66.1	$64.2	$61.4	$59.2	$56.9	$54.0	$51.1	$46.2	$41.0	-$1.0
$26	$71.5	$69.5	$66.5	$64.2	$61.8	$58.8	$55.8	$50.6	$45.2	-$1.0
$27	$76.8	$74.8	$71.7	$69.3	$66.8	$63.6	$60.4	$55.1	$49.4	-$1.0
$28	$82.1	$80.0	$76.8	$74.3	$71.7	$68.4	$65.1	$59.6	$53.6	-$1.0
$29	$87.5	$85.3	$81.9	$79.3	$76.6	$73.2	$69.8	$64.0	$57.9	-$1.0
$30	$92.9	$90.5	$87.1	$84.4	$81.6	$78.1	$74.5	$68.5	$62.1	-$1.0
$31	$98.2	$95.8	$92.2	$89.4	$86.5	$82.9	$79.1	$73.0	$66.4	-$1.0
$32	$103.6	$101.1	$97.4	$94.5	$91.5	$87.7	$83.8	$77.5	$70.7	-$1.0
$33	$109.0	$106.3	$102.5	$99.6	$96.4	$92.5	$88.5	$82.0	$74.9	-$1.0
$34	$114.3	$111.6	$107.7	$104.6	$101.4	$97.3	$93.2	$86.4	$79.2	-$1.0
$35	$119.7	$116.9	$112.8	$109.7	$106.3	$102.2	$97.9	$90.9	$83.5	-$1.0
$36	$125.1	$122.1	$118.0	$114.7	$111.3	$107.0	$102.6	$95.4	$87.7	-$1.0
$37	$130.4	$127.4	$123.1	$119.8	$116.2	$111.8	$107.3	$99.9	$92.0	-$1.0
$38	$135.8	$132.7	$128.3	$124.8	$121.2	$116.6	$112.0	$104.4	$96.3	-$1.0
$39	$141.2	$138.0	$133.4	$129.9	$126.1	$121.4	$116.7	$108.8	$100.5	-$1.0
$40	$146.5	$143.3	$138.6	$135.0	$131.1	$126.3	$121.4	$113.3	$104.8	-$1.0

Table 9.1(f): Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=12 yrs)

t=16 yrs	Primary	Secondary	Abandon

Oil Price s ($/bbl)	Cumulative Primary Oil $\mathcal{P}_1$ (MSTB)									
	0	100	200	300	400	500	600	700	800	843
$0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$1	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$2	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$3	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$4	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$5	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$6	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$7	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$8	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$9	-$0.7	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$10	-$0.6	-$0.8	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$11	-$0.4	-$0.7	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$12	-$0.1	-$0.5	-$0.8	-$0.9	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$13	$3.0	$2.0	$0.8	-$0.2	-$0.8	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0
$14	$8.1	$7.0	$5.7	$4.7	$3.6	$2.1	$0.7	-$1.0	-$1.0	-$1.0
$15	$13.2	$12.1	$10.6	$9.5	$8.3	$6.6	$5.1	$2.1	-$1.0	-$1.0
$16	$18.4	$17.2	$15.6	$14.3	$13.1	$11.2	$9.6	$6.4	$2.9	-$1.0
$17	$23.5	$22.2	$20.5	$19.1	$17.8	$15.8	$14.1	$10.6	$6.9	-$1.0
$18	$28.7	$27.3	$25.5	$24.0	$22.6	$20.5	$18.6	$14.9	$10.9	-$1.0
$19	$33.8	$32.4	$30.5	$28.8	$27.3	$25.1	$23.0	$19.2	$14.9	-$1.0
$20	$39.0	$37.5	$35.5	$33.7	$32.1	$29.8	$27.5	$23.5	$18.9	-$1.0
$21	$44.3	$42.6	$40.5	$38.6	$36.9	$34.4	$32.0	$27.8	$22.9	-$1.0
$22	$49.5	$47.8	$45.5	$43.5	$41.6	$39.1	$36.6	$32.1	$27.0	-$1.0
$23	$54.7	$52.9	$50.5	$48.4	$46.4	$43.7	$41.1	$36.4	$31.0	-$1.0
$24	$59.9	$58.1	$55.4	$53.3	$51.2	$48.4	$45.6	$40.8	$35.0	-$1.0
$25	$65.1	$63.2	$60.5	$58.3	$56.0	$53.1	$50.2	$45.1	$39.1	-$1.0
$26	$70.4	$68.3	$65.5	$63.2	$60.9	$57.8	$54.7	$49.4	$43.1	-$1.0
$27	$75.6	$73.5	$70.5	$68.1	$65.7	$62.5	$59.3	$53.7	$47.2	-$1.0
$28	$80.8	$78.6	$75.5	$73.0	$70.5	$67.2	$63.9	$58.1	$51.3	-$1.0
$29	$86.1	$83.8	$80.5	$78.0	$75.3	$71.9	$68.4	$62.4	$55.3	-$1.0
$30	$91.3	$88.9	$85.6	$82.9	$80.2	$76.6	$73.0	$66.8	$59.4	-$1.0
$31	$96.6	$94.1	$90.6	$87.8	$85.0	$81.3	$77.6	$71.1	$63.5	-$1.0
$32	$101.8	$99.2	$95.6	$92.8	$89.8	$86.0	$82.1	$75.4	$67.6	-$1.0
$33	$107.1	$104.4	$100.7	$97.7	$94.7	$90.7	$86.7	$79.8	$71.6	-$1.0
$34	$112.3	$109.5	$105.7	$102.6	$99.5	$95.4	$91.3	$84.1	$75.7	-$1.0
$35	$117.5	$114.7	$110.7	$107.6	$104.3	$100.1	$95.8	$88.4	$79.8	-$1.0
$36	$122.8	$119.8	$115.7	$112.5	$109.2	$104.8	$100.4	$92.8	$83.9	-$1.0
$37	$128.0	$125.0	$120.8	$117.4	$114.0	$109.5	$105.0	$97.1	$87.9	-$1.0
$38	$133.3	$130.1	$125.8	$122.4	$118.8	$114.2	$109.5	$101.5	$92.0	-$1.0
$39	$138.5	$135.3	$130.8	$127.3	$123.6	$118.9	$114.1	$105.8	$96.1	-$1.0
$40	$143.8	$140.4	$135.9	$132.2	$128.5	$123.6	$118.7	$110.1	$100.1	-$1.0

Table 9.1(g): Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=16 yrs)

t=20 yrs	Primary	Secondary	Abandon

Oil Price	Cumulative Primary Oil $\mathcal{P}_1$ (MSTB)									
s ($/bbl)	0	100	200	300	400	500	600	700	800	843
$0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$1	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$2	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$3	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$4	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$5	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$6	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$7	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$8	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$9	-$0.7	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$10	-$0.6	-$0.8	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$11	-$0.4	-$0.7	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$12	-$0.1	-$0.5	-$0.8	-$0.9	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$13	$1.8	$0.9	-$0.3	-$0.7	-$0.8	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0
$14	$6.7	$5.7	$4.4	$3.4	$2.3	$0.9	-$0.5	-$1.0	-$1.0	-$1.0
$15	$11.5	$10.5	$9.0	$8.0	$6.8	$5.2	$3.7	$0.8	-$1.0	-$1.0
$16	$16.4	$15.2	$13.7	$12.5	$11.3	$9.6	$7.9	$4.8	$1.2	-$1.0
$17	$21.3	$20.0	$18.4	$17.1	$15.8	$13.9	$12.1	$8.8	$4.9	-$1.0
$18	$26.1	$24.8	$23.0	$21.6	$20.2	$18.3	$16.3	$12.8	$8.6	-$1.0
$19	$31.0	$29.6	$27.7	$26.2	$24.7	$22.6	$20.5	$16.8	$12.4	-$1.0
$20	$35.9	$34.4	$32.4	$30.8	$29.2	$27.0	$24.7	$20.8	$16.1	-$1.0
$21	$40.8	$39.2	$37.0	$35.4	$33.7	$31.3	$29.0	$24.8	$19.8	-$1.0
$22	$45.6	$44.0	$41.7	$40.0	$38.2	$35.7	$33.2	$28.8	$23.5	-$1.0
$23	$50.5	$48.8	$46.4	$44.6	$42.6	$40.1	$37.4	$32.8	$27.2	-$1.0
$24	$55.4	$53.6	$51.1	$49.1	$47.1	$44.4	$41.6	$36.8	$31.0	-$1.0
$25	$60.3	$58.4	$55.7	$53.7	$51.6	$48.8	$45.9	$40.8	$34.7	-$1.0
$26	$65.2	$63.1	$60.4	$58.3	$56.1	$53.1	$50.1	$44.8	$38.4	-$1.0
$27	$70.0	$67.9	$65.1	$62.9	$60.6	$57.5	$54.3	$48.8	$42.2	-$1.0
$28	$74.9	$72.7	$69.8	$67.5	$65.1	$61.9	$58.6	$52.8	$45.9	-$1.0
$29	$79.8	$77.5	$74.4	$72.1	$69.6	$66.2	$62.8	$56.8	$49.6	-$1.0
$30	$84.7	$82.3	$79.1	$76.7	$74.1	$70.6	$67.0	$60.8	$53.4	-$1.0
$31	$89.6	$87.1	$83.8	$81.3	$78.6	$75.0	$71.3	$64.8	$57.1	-$1.0
$32	$94.4	$91.9	$88.5	$85.8	$83.1	$79.3	$75.5	$68.8	$60.8	-$1.0
$33	$99.3	$96.7	$93.1	$90.4	$87.6	$83.7	$79.7	$72.8	$64.5	-$1.0
$34	$104.2	$101.5	$97.8	$95.0	$92.1	$88.1	$84.0	$76.8	$68.3	-$1.0
$35	$109.1	$106.3	$102.5	$99.6	$96.6	$92.4	$88.2	$80.8	$72.0	-$1.0
$36	$114.0	$111.1	$107.2	$104.2	$101.0	$96.8	$92.4	$84.8	$75.7	-$1.0
$37	$118.9	$115.9	$111.9	$108.8	$105.5	$101.2	$96.7	$88.8	$79.5	-$1.0
$38	$123.7	$120.7	$116.5	$113.4	$110.0	$105.5	$100.9	$92.8	$83.2	-$1.0
$39	$128.6	$125.5	$121.2	$118.0	$114.5	$109.9	$105.2	$96.8	$86.9	-$1.0
$40	$133.5	$130.3	$125.9	$122.6	$119.0	$114.2	$109.4	$100.8	$90.7	-$1.0

Table 9.1(h): Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=20 yrs)

t=24 yrs	Primary	Secondary	Abandon

Oil Price s ($/bbl)	Cumulative Primary Oil $\mathcal{P}_1$ (MSTB)									
	0	100	200	300	400	500	600	700	800	843
$0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$1	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$2	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$3	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$4	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$5	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$6	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$7	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$8	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$9	-$0.7	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$10	-$0.6	-$0.8	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$11	-$0.4	-$0.7	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$12	-$0.1	-$0.5	-$0.8	-$0.9	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$13	$0.2	-$0.2	-$0.5	-$0.7	-$0.8	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0
$14	$0.9	$0.1	-$0.3	-$0.5	-$0.7	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0
$15	$4.9	$4.0	$2.6	$1.6	$0.5	-$0.8	-$1.0	-$1.0	-$1.0	-$1.0
$16	$8.9	$7.9	$6.4	$5.4	$4.2	$2.7	$0.9	-$1.0	-$1.0	-$1.0
$17	$13.0	$11.8	$10.2	$9.1	$7.8	$6.2	$4.4	$1.4	-$1.0	-$1.0
$18	$17.0	$15.8	$14.1	$12.9	$11.5	$9.7	$7.8	$4.6	$0.4	-$1.0
$19	$21.0	$19.7	$17.9	$16.6	$15.1	$13.3	$11.2	$7.9	$3.3	-$1.0
$20	$25.0	$23.7	$21.7	$20.4	$18.8	$16.8	$14.6	$11.1	$6.2	-$1.0
$21	$29.0	$27.6	$25.5	$24.1	$22.5	$20.4	$18.0	$14.3	$9.2	-$1.0
$22	$33.0	$31.5	$29.4	$27.9	$26.1	$23.9	$21.4	$17.5	$12.1	-$1.0
$23	$37.0	$35.5	$33.2	$31.6	$29.8	$27.4	$24.8	$20.7	$15.0	-$1.0
$24	$41.1	$39.4	$37.0	$35.4	$33.4	$31.0	$28.2	$23.9	$17.9	-$1.0
$25	$45.1	$43.3	$40.8	$39.1	$37.1	$34.5	$31.7	$27.1	$20.9	-$1.0
$26	$49.1	$47.3	$44.7	$42.9	$40.7	$38.1	$35.1	$30.3	$23.8	-$1.0
$27	$53.1	$51.2	$48.5	$46.6	$44.4	$41.6	$38.5	$33.5	$26.7	-$1.0
$28	$57.1	$55.2	$52.3	$50.4	$48.1	$45.1	$41.9	$36.7	$29.6	-$1.0
$29	$61.1	$59.1	$56.1	$54.1	$51.7	$48.7	$45.3	$39.9	$32.6	-$1.0
$30	$65.2	$63.0	$60.0	$57.9	$55.4	$52.2	$48.7	$43.1	$35.5	-$1.0
$31	$69.2	$67.0	$63.8	$61.6	$59.0	$55.8	$52.1	$46.3	$38.4	-$1.0
$32	$73.2	$70.9	$67.6	$65.4	$62.7	$59.3	$55.5	$49.6	$41.3	-$1.0
$33	$77.2	$74.9	$71.5	$69.1	$66.3	$62.9	$59.0	$52.8	$44.3	-$1.0
$34	$81.2	$78.8	$75.3	$72.9	$70.0	$66.4	$62.4	$56.0	$47.2	-$1.0
$35	$85.2	$82.7	$79.1	$76.6	$73.7	$69.9	$65.8	$59.2	$50.1	-$1.0
$36	$89.2	$86.7	$82.9	$80.4	$77.3	$73.5	$69.2	$62.4	$53.1	-$1.0
$37	$93.3	$90.6	$86.8	$84.1	$81.0	$77.0	$72.6	$65.6	$56.0	-$1.0
$38	$97.3	$94.5	$90.6	$87.9	$84.6	$80.6	$76.0	$68.8	$58.9	-$1.0
$39	$101.3	$98.5	$94.4	$91.6	$88.3	$84.1	$79.4	$72.0	$61.8	-$1.0
$40	$105.3	$102.4	$98.2	$95.4	$91.9	$87.6	$82.9	$75.2	$64.8	-$1.0

Table 9.1(i): Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=24 yrs)

t=28 yrs	Primary	Secondary	Abandon							
Oil Price	Cumulative Primary Oil $\mathcal{P}_1$ (MSTB)									
s ($/bbl)	0	100	200	300	400	500	600	700	800	843
$0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$1	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$2	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$3	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$4	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$5	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$6	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$7	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$8	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$9	-$0.7	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$10	-$0.6	-$0.8	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$11	-$0.4	-$0.7	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$12	-$0.1	-$0.5	-$0.8	-$0.9	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0	-$1.0
$13	$0.1	-$0.3	-$0.6	-$0.7	-$0.8	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0
$14	$0.4	-$0.1	-$0.4	-$0.6	-$0.7	-$0.9	-$1.0	-$1.0	-$1.0	-$1.0
$15	$0.7	$0.2	-$0.2	-$0.4	-$0.6	-$0.8	-$1.0	-$1.0	-$1.0	-$1.0
$16	$1.0	$0.4	$0.0	-$0.2	-$0.4	-$0.7	-$0.9	-$1.0	-$1.0	-$1.0
$17	$1.3	$0.7	$0.2	$0.0	-$0.3	-$0.6	-$0.8	-$1.0	-$1.0	-$1.0
$18	$1.5	$0.9	$0.4	$0.2	-$0.1	-$0.4	-$0.8	-$1.0	-$1.0	-$1.0
$19	$1.8	$1.1	$0.7	$0.4	$0.0	-$0.3	-$0.7	-$0.9	-$1.0	-$1.0
$20	$2.1	$1.4	$0.9	$0.6	$0.2	-$0.2	-$0.6	-$0.9	-$1.0	-$1.0
$21	$2.9	$1.7	$1.1	$0.7	$0.4	$0.0	-$0.5	-$0.8	-$0.9	-$1.0
$22	$5.2	$4.0	$2.1	$0.9	$0.6	$0.1	-$0.3	-$0.7	-$0.9	-$1.0
$23	$7.6	$6.2	$4.2	$3.0	$1.5	$0.3	-$0.2	-$0.6	-$0.9	-$1.0
$24	$9.9	$8.5	$6.4	$5.1	$3.5	$1.7	-$0.1	-$0.6	-$0.8	-$1.0
$25	$12.2	$10.8	$8.6	$7.2	$5.5	$3.7	$1.6	-$0.5	-$0.8	-$1.0
$26	$14.6	$13.0	$10.8	$9.3	$7.6	$5.6	$3.4	-$0.1	-$0.8	-$1.0
$27	$16.9	$15.3	$12.9	$11.5	$9.6	$7.6	$5.3	$1.6	-$0.7	-$1.0
$28	$19.3	$17.6	$15.1	$13.6	$11.7	$9.5	$7.1	$3.3	-$0.7	-$1.0
$29	$21.6	$19.9	$17.3	$15.7	$13.7	$11.5	$9.0	$5.0	-$0.3	-$1.0
$30	$23.9	$22.1	$19.5	$17.8	$15.7	$13.4	$10.9	$6.7	$1.2	-$1.0
$31	$26.3	$24.4	$21.6	$19.9	$17.8	$15.4	$12.7	$8.4	$2.7	-$1.0
$32	$28.6	$26.7	$23.8	$22.0	$19.8	$17.3	$14.6	$10.1	$4.2	-$1.0
$33	$30.9	$28.9	$26.0	$24.1	$21.8	$19.3	$16.4	$11.8	$5.7	-$1.0
$34	$33.3	$31.2	$28.1	$26.2	$23.9	$21.2	$18.3	$13.5	$7.2	-$1.0
$35	$35.6	$33.5	$30.3	$28.4	$25.9	$23.2	$20.2	$15.2	$8.7	-$1.0
$36	$37.9	$35.7	$32.5	$30.5	$27.9	$25.1	$22.0	$17.0	$10.2	-$1.0
$37	$40.3	$38.0	$34.7	$32.6	$30.0	$27.1	$23.9	$18.7	$11.7	-$1.0
$38	$42.6	$40.3	$36.8	$34.7	$32.0	$29.0	$25.7	$20.4	$13.2	-$1.0
$39	$45.0	$42.6	$39.0	$36.8	$34.1	$31.0	$27.6	$22.1	$14.7	-$1.0
$40	$47.3	$44.8	$41.2	$38.9	$36.1	$33.0	$29.4	$23.8	$16.2	-$1.0

Table 9.1(j): Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=28 yrs)

t=0 yrs	Produce	Abandon

Oil Price s ($/bbl)	Cumulative Secondary Oil $\mathcal{P}_2$ (MSTB) for Primary Oil $\mathcal{P}_1$=0 MSTB
	0
$0	-$2.6
$1	-$2.6
$2	-$2.6
$3	-$2.6
$4	-$2.6
$5	-$1.8
$6	$1.5
$7	$5.7
$8	$10.4
$9	$15.4
$10	$20.4
$11	$25.6
$12	$30.8
$13	$36.1
$14	$41.3
$15	$46.6
$16	$51.9
$17	$57.1
$18	$62.4
$19	$67.7
$20	$73.1
$21	$78.5
$22	$83.9
$23	$89.3
$24	$94.8
$25	$100.2
$26	$105.6
$27	$111.1
$28	$116.5
$29	$122.0
$30	$127.5
$31	$133.0
$32	$138.4
$33	$144.0
$34	$149.5
$35	$155.0
$36	$160.5
$37	$166.0
$38	$171.5
$39	$177.0
$40	$182.5

Table 9.2(a): Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ ($million) and Action Regions (t=0 yrs, $\mathcal{P}_1$=0 MSTB)

t=2 yrs	Produce	Abandon

Oil Price s ($/bbl)	Cumulative Secondary Oil $\mathcal{P}_2$ (MSTB) for Primary Oil $\mathcal{P}_1$=0 MSTB			
	0	500	1000	1408
$0	-$2.6	-$2.6	-$2.6	-$2.6
$1	-$2.6	-$2.6	-$2.6	-$2.6
$2	-$2.6	-$2.6	-$2.6	-$2.6
$3	-$2.6	-$2.6	-$2.6	-$2.6
$4	-$2.6	-$2.6	-$2.6	-$2.6
$5	-$1.8	-$1.2	-$1.3	-$1.3
$6	$1.5	$2.0	$1.7	$1.5
$7	$5.6	$6.1	$5.6	$5.2
$8	$10.2	$10.6	$9.9	$9.4
$9	$15.1	$15.4	$14.5	$13.8
$10	$20.1	$20.3	$19.1	$18.3
$11	$25.2	$25.3	$23.9	$22.9
$12	$30.4	$30.4	$28.7	$27.6
$13	$35.6	$35.5	$33.6	$32.2
$14	$40.8	$40.5	$38.4	$36.9
$15	$46.0	$45.6	$43.3	$41.6
$16	$51.2	$50.7	$48.1	$46.3
$17	$56.4	$55.8	$53.0	$51.0
$18	$61.7	$61.0	$57.9	$55.7
$19	$66.9	$66.1	$62.8	$60.5
$20	$72.2	$71.3	$67.8	$65.3
$21	$77.6	$76.6	$72.8	$70.2
$22	$82.9	$81.8	$77.9	$75.0
$23	$88.3	$87.1	$82.9	$79.9
$24	$93.6	$92.4	$87.9	$84.8
$25	$99.0	$97.6	$93.0	$89.7
$26	$104.4	$102.9	$98.0	$94.6
$27	$109.8	$108.2	$103.1	$99.5
$28	$115.2	$113.5	$108.2	$104.4
$29	$120.6	$118.8	$113.3	$109.3
$30	$126.0	$124.2	$118.4	$114.2
$31	$131.5	$129.5	$123.5	$119.2
$32	$136.9	$134.8	$128.6	$124.1
$33	$142.3	$140.2	$133.7	$129.1
$34	$147.8	$145.5	$138.8	$134.0
$35	$153.2	$150.9	$143.9	$139.0
$36	$158.7	$156.2	$149.1	$144.0
$37	$164.1	$161.6	$154.2	$148.9
$38	$169.6	$166.9	$159.3	$153.9
$39	$175.0	$172.3	$164.4	$158.8
$40	$180.5	$177.6	$169.5	$163.8

Table 9.2(b): Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ ($million) and Action Regions (t=2 yrs, $\mathcal{P}_1$=0 MSTB)

t=4 yrs	Produce	Abandon						
Oil Price s ($/bbl)	Cumulative Secondary Oil $\mathcal{P}_2$ (MSTB) for Primary Oil $\mathcal{P}_1$=0 MSTB							
	0	500	1000	1500	2000	2500	3000	3451
$0	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$1	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$2	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$3	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$4	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$5	-$1.8	-$1.2	-$1.3	-$1.3	-$1.5	-$1.7	-$2.0	-$2.2
$6	$1.5	$2.0	$1.7	$1.4	$0.9	$0.5	$0.0	-$0.5
$7	$5.6	$6.0	$5.5	$5.0	$4.3	$3.6	$2.8	$2.2
$8	$10.2	$10.6	$9.8	$9.0	$8.1	$7.1	$6.1	$5.2
$9	$15.1	$15.3	$14.3	$13.3	$12.1	$10.9	$9.6	$8.5
$10	$20.1	$20.2	$19.0	$17.7	$16.3	$14.8	$13.2	$11.9
$11	$25.2	$25.2	$23.7	$22.3	$20.5	$18.8	$16.9	$15.4
$12	$30.3	$30.3	$28.5	$26.8	$24.8	$22.8	$20.6	$18.9
$13	$35.5	$35.3	$33.4	$31.4	$29.1	$26.8	$24.4	$22.4
$14	$40.7	$40.4	$38.2	$36.0	$33.5	$30.9	$28.1	$25.9
$15	$45.9	$45.5	$43.0	$40.5	$37.8	$34.9	$31.9	$29.4
$16	$51.1	$50.5	$47.8	$45.1	$42.1	$38.9	$35.7	$33.0
$17	$56.3	$55.6	$52.7	$49.7	$46.4	$43.0	$39.4	$36.5
$18	$61.5	$60.7	$57.6	$54.4	$50.8	$47.1	$43.3	$40.1
$19	$66.8	$65.9	$62.5	$59.0	$55.2	$51.3	$47.2	$43.8
$20	$72.1	$71.1	$67.4	$63.8	$59.7	$55.5	$51.1	$47.5
$21	$77.4	$76.3	$72.4	$68.5	$64.2	$59.7	$55.1	$51.2
$22	$82.7	$31.5	$77.4	$73.3	$68.7	$64.0	$59.0	$55.0
$23	$88.1	$86.8	$82.4	$78.0	$73.2	$68.2	$63.0	$58.7
$24	$93.4	$92.0	$87.4	$82.8	$77.7	$72.4	$67.0	$62.5
$25	$98.8	$97.3	$92.4	$87.6	$82.2	$76.7	$70.9	$66.2
$26	$104.1	$102.5	$97.5	$92.4	$86.7	$80.9	$74.9	$70.0
$27	$109.5	$107.8	$102.5	$97.2	$91.3	$85.2	$78.9	$73.7
$28	$114.9	$113.1	$107.5	$102.0	$95.8	$89.5	$82.9	$77.5
$29	$120.3	$118.4	$112.6	$106.8	$100.4	$93.8	$87.0	$81.3
$30	$125.7	$123.7	$117.7	$111.6	$105.0	$98.1	$91.0	$85.2
$31	$131.1	$129.0	$122.8	$116.5	$109.6	$102.4	$95.0	$89.0
$32	$136.6	$134.3	$127.8	$121.3	$114.1	$106.8	$99.1	$92.8
$33	$142.0	$139.6	$132.9	$126.2	$118.7	$111.1	$103.2	$96.6
$34	$147.4	$144.9	$138.0	$131.0	$123.3	$115.4	$107.2	$100.5
$35	$152.8	$150.3	$143.1	$135.9	$127.9	$119.7	$111.3	$104.3
$36	$158.3	$155.6	$148.2	$140.7	$132.5	$124.1	$115.3	$108.1
$37	$163.7	$160.9	$153.3	$145.6	$137.1	$128.4	$119.4	$111.9
$38	$169.1	$166.2	$158.4	$150.4	$141.7	$132.7	$123.4	$115.8
$39	$174.5	$171.5	$163.4	$155.3	$146.3	$137.1	$127.5	$119.6
$40	$180.0	$176.9	$168.5	$160.1	$150.9	$141.4	$131.5	$123.4

Table 9.2(c): Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ ($million) and Action Regions (t=4 yrs, $\mathcal{P}_1$=0 MSTB)

t=8 yrs	Produce	Abandon

Oil Price s ($/bbl)	Cumulative Secondary Oil $\mathcal{P}_2$ (MSTB) for Primary Oil $\mathcal{P}_1$=0 MSTB													
	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6404
$0	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$1	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$2	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$3	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$4	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$5	-$1.8	-$1.2	-$1.3	-$1.3	-$1.5	-$1.7	-$2.0	-$2.2	-$2.4	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$6	$1.5	$2.0	$1.7	$1.4	$0.9	$0.5	-$0.1	-$0.6	-$1.1	-$1.5	-$1.8	-$2.1	-$2.3	-$2.4
$7	$5.6	$6.0	$5.5	$5.0	$4.3	$3.5	$2.8	$2.0	$1.2	$0.5	-$0.1	-$0.6	-$1.0	-$1.3
$8	$10.2	$10.6	$9.8	$9.0	$8.1	$7.1	$6.0	$4.9	$3.9	$2.9	$2.1	$1.3	$0.6	$0.1
$9	$15.1	$15.3	$14.3	$13.3	$12.1	$10.8	$9.5	$8.1	$6.8	$5.5	$4.4	$3.3	$2.3	$1.6
$10	$20.1	$20.2	$19.0	$17.7	$16.2	$14.7	$13.1	$11.4	$9.8	$8.2	$6.8	$5.5	$4.2	$3.3
$11	$25.2	$25.2	$23.7	$22.2	$20.4	$18.6	$16.7	$14.8	$12.9	$11.0	$9.3	$7.7	$6.2	$5.1
$12	$30.3	$30.2	$28.5	$26.7	$24.7	$22.6	$20.4	$18.2	$16.0	$13.8	$11.9	$10.0	$8.2	$6.8
$13	$35.5	$35.3	$33.3	$31.3	$29.0	$26.6	$24.2	$21.6	$19.1	$16.7	$14.4	$12.2	$10.1	$8.6
$14	$40.7	$40.3	$38.1	$35.9	$33.3	$30.7	$27.9	$25.1	$22.3	$19.5	$17.0	$14.5	$12.1	$10.3
$15	$45.9	$45.4	$42.9	$40.4	$37.6	$34.7	$31.6	$28.5	$25.4	$22.4	$19.6	$16.8	$14.1	$12.1
$16	$51.1	$50.5	$47.8	$45.0	$41.9	$38.7	$35.4	$31.9	$28.6	$25.2	$22.1	$19.1	$16.1	$13.9
$17	$56.3	$55.6	$52.6	$49.6	$46.2	$42.8	$39.1	$35.4	$31.7	$28.1	$24.8	$21.5	$18.2	$15.8
$18	$61.5	$60.7	$57.5	$54.2	$50.6	$46.9	$42.9	$39.0	$35.0	$31.1	$27.5	$23.9	$20.4	$17.8
$19	$66.7	$65.8	$62.4	$58.9	$55.0	$51.0	$46.8	$42.5	$38.3	$34.1	$30.2	$26.4	$22.6	$19.8
$20	$72.0	$71.0	$67.3	$63.6	$59.4	$55.1	$50.7	$46.1	$41.6	$37.1	$33.0	$28.9	$24.9	$21.8
$21	$77.3	$76.2	$72.3	$68.3	$63.9	$59.3	$54.6	$49.7	$44.9	$40.2	$35.7	$31.4	$27.1	$23.9
$22	$82.7	$81.4	$77.2	$73.0	$68.4	$63.5	$58.5	$53.4	$48.3	$43.2	$38.5	$33.9	$29.3	$25.9
$23	$88.0	$86.6	$82.2	$77.8	$72.8	$67.7	$62.4	$57.0	$51.6	$46.3	$41.3	$36.4	$31.6	$27.9
$24	$93.3	$91.9	$87.2	$82.5	$77.3	$71.9	$66.3	$60.7	$55.0	$49.4	$44.1	$38.9	$33.8	$30.0
$25	$98.7	$97.1	$92.2	$87.3	$81.8	$76.2	$70.3	$64.3	$58.3	$52.5	$46.9	$41.4	$36.1	$32.1
$26	$104.0	$102.3	$97.2	$92.0	$86.3	$80.4	$74.2	$68.0	$61.7	$55.6	$49.8	$44.0	$38.4	$34.1
$27	$109.4	$107.6	$102.3	$96.8	$90.8	$84.7	$78.2	$71.7	$65.1	$58.7	$52.6	$46.6	$40.7	$36.3
$28	$114.8	$112.9	$107.3	$101.6	$95.4	$88.9	$82.2	$75.4	$68.5	$61.8	$55.5	$49.2	$43.0	$38.4
$29	$120.2	$118.2	$112.3	$106.4	$99.9	$93.2	$86.2	$79.1	$72.0	$64.9	$58.3	$51.8	$45.4	$40.5
$30	$125.6	$123.4	$117.4	$111.2	$104.5	$97.5	$90.2	$82.8	$75.4	$68.1	$61.2	$54.4	$47.7	$42.7
$31	$131.0	$128.7	$122.4	$116.0	$109.0	$101.7	$94.2	$86.5	$78.8	$71.2	$64.1	$57.0	$50.0	$44.8
$32	$136.4	$134.0	$127.5	$120.9	$113.6	$106.0	$98.2	$90.2	$82.3	$74.4	$67.0	$59.6	$52.4	$46.9
$33	$141.8	$139.3	$132.6	$125.7	$118.1	$110.3	$102.2	$93.9	$85.7	$77.5	$69.9	$62.2	$54.7	$49.1
$34	$147.2	$144.6	$137.6	$130.5	$122.7	$114.6	$106.2	$97.7	$89.1	$80.7	$72.7	$64.8	$57.1	$51.2
$35	$152.6	$149.9	$142.7	$135.3	$127.2	$118.9	$110.2	$101.4	$92.6	$83.8	$75.6	$67.4	$59.4	$53.3
$36	$158.0	$155.2	$147.7	$140.1	$131.8	$123.2	$114.2	$105.1	$96.0	$87.0	$78.5	$70.0	$61.7	$55.5
$37	$163.4	$160.5	$152.8	$145.0	$136.4	$127.5	$118.2	$108.8	$99.4	$90.2	$81.4	$72.6	$64.1	$57.6
$38	$168.8	$165.8	$157.9	$149.8	$140.9	$131.8	$122.2	$112.6	$102.9	$93.3	$84.3	$75.2	$66.4	$59.8
$39	$174.2	$171.1	$162.9	$154.6	$145.5	$136.0	$126.2	$116.3	$106.3	$96.5	$87.1	$77.9	$68.7	$61.9
$40	$179.6	$176.5	$168.0	$159.4	$150.1	$140.3	$130.2	$120.0	$109.7	$99.6	$90.0	$80.5	$71.1	$64.0

Table 9.2(d): Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ ($million) and Action Regions (t=8 yrs, $\mathcal{P}_1$=0 MSTB)

t=12 yrs	Produce	Abandon

Oil Price s ($/bbl)	Cumulative Secondary Oil $\mathcal{P}_2$ (MSTB) for Primary Oil $\mathcal{P}_1$=0 MSTB																	
	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8405
$0	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$1	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$2	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$3	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$4	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$5	-$1.8	-$1.2	-$1.3	-$1.3	-$1.5	-$1.7	-$2.0	-$2.2	-$2.4	-$2.6	-$2.8	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$6	$1.5	$2.0	$1.7	$1.4	$0.9	$0.5	-$0.1	-$0.6	-$1.1	-$1.5	-$1.8	-$2.1	-$2.3	-$2.4	-$2.8	-$2.6	-$2.6	-$2.6
$7	$5.6	$6.0	$5.5	$5.0	$4.3	$3.5	$2.8	$2.0	$1.2	$0.5	-$0.1	-$0.6	-$1.0	-$1.5	-$1.9	-$2.3	-$2.5	-$2.6
$8	$10.2	$10.6	$9.8	$9.0	$8.1	$7.1	$6.0	$4.9	$3.9	$2.9	$2.1	$1.3	$0.5	-$0.2	-$0.9	-$1.6	-$2.2	-$2.5
$9	$15.1	$15.3	$14.3	$13.3	$12.1	$10.8	$9.5	$8.1	$6.8	$5.5	$4.4	$3.3	$2.3	$1.2	$0.2	-$0.8	-$1.7	-$2.2
$10	$20.1	$20.2	$19.0	$17.7	$16.2	$14.7	$13.0	$11.4	$9.8	$8.2	$6.8	$5.4	$4.1	$2.8	$1.5	$0.2	-$1.0	-$1.8
$11	$25.2	$25.2	$23.7	$22.2	$20.4	$18.6	$16.7	$14.8	$12.8	$11.0	$9.3	$7.7	$6.1	$4.5	$2.9	$1.3	-$0.3	-$1.3
$12	$30.3	$30.2	$28.5	$26.7	$24.7	$22.6	$20.4	$18.2	$16.0	$13.8	$11.8	$9.9	$8.0	$6.1	$4.2	$2.3	$0.4	-$0.9
$13	$35.5	$35.3	$33.3	$31.3	$29.0	$26.6	$24.1	$21.6	$19.1	$16.6	$14.4	$12.2	$10.0	$7.8	$5.6	$3.3	$1.1	-$0.5
$14	$40.7	$40.3	$38.1	$35.9	$33.3	$30.7	$27.9	$25.1	$22.2	$19.5	$17.0	$14.4	$12.0	$9.5	$6.9	$4.3	$1.8	$0.0
$15	$45.9	$45.4	$42.9	$40.4	$37.6	$34.7	$31.6	$28.5	$25.4	$22.3	$19.5	$16.7	$13.9	$11.1	$8.3	$5.4	$2.5	$0.5
$16	$51.0	$50.5	$47.8	$45.0	$41.9	$38.7	$35.3	$31.9	$28.5	$25.2	$22.1	$19.0	$16.0	$12.9	$9.7	$6.5	$3.4	$1.1
$17	$56.2	$55.5	$52.6	$49.6	$46.2	$42.8	$39.1	$35.4	$31.7	$28.1	$24.7	$21.3	$18.0	$14.7	$11.2	$7.8	$4.4	$1.9
$18	$61.5	$60.7	$57.5	$54.2	$50.6	$46.8	$42.9	$38.9	$35.0	$31.0	$27.4	$23.7	$20.2	$16.5	$12.8	$9.1	$5.3	$2.6
$19	$66.7	$65.8	$62.4	$58.9	$55.0	$51.0	$46.8	$42.5	$38.2	$34.0	$30.1	$26.2	$22.3	$18.4	$14.4	$10.3	$6.3	$3.4
$20	$72.0	$71.0	$67.3	$63.6	$59.4	$55.1	$50.6	$46.1	$41.5	$37.1	$32.8	$28.6	$24.5	$20.3	$16.0	$11.6	$7.3	$4.1
$21	$77.3	$76.1	$72.2	$68.3	$63.9	$59.3	$54.5	$49.7	$44.9	$40.1	$35.6	$31.1	$26.7	$22.2	$17.6	$12.9	$8.3	$4.9
$22	$82.6	$81.3	$77.2	$73.0	$68.3	$63.5	$58.4	$53.3	$48.2	$43.1	$38.4	$33.6	$28.9	$24.1	$19.2	$14.3	$9.3	$5.7
$23	$87.9	$86.6	$82.2	$77.7	$72.8	$67.7	$62.4	$56.9	$51.5	$46.2	$41.1	$36.1	$31.1	$26.0	$20.8	$15.6	$10.4	$6.5
$24	$93.2	$91.8	$87.2	$82.5	$77.3	$71.9	$66.3	$60.6	$54.9	$49.2	$43.9	$38.6	$33.3	$28.0	$22.5	$17.0	$11.4	$7.3
$25	$98.5	$97.0	$92.1	$87.2	$81.8	$76.1	$70.2	$64.2	$58.2	$52.3	$46.7	$41.1	$35.6	$30.0	$24.2	$18.4	$12.5	$8.2
$26	$103.9	$102.2	$97.1	$92.0	$86.2	$80.3	$74.1	$67.9	$61.6	$55.4	$49.5	$43.7	$37.9	$31.9	$25.9	$19.8	$13.7	$9.1
$27	$109.2	$107.5	$102.1	$96.7	$90.7	$84.6	$78.1	$71.6	$65.0	$58.5	$52.4	$46.2	$40.1	$33.9	$27.6	$21.2	$14.8	$10.0
$28	$114.5	$112.7	$107.2	$101.5	$95.3	$88.8	$82.1	$75.2	$68.4	$61.6	$55.2	$48.8	$42.4	$35.9	$29.3	$22.6	$15.9	$10.9
$29	$119.9	$118.0	$112.2	$106.3	$99.8	$93.1	$86.0	$78.9	$71.8	$64.7	$58.1	$51.4	$44.7	$37.9	$31.0	$24.0	$17.0	$11.7
$30	$125.3	$123.2	$117.2	$111.1	$104.3	$97.3	$90.0	$82.6	$75.2	$67.9	$60.9	$53.9	$47.0	$40.0	$32.7	$25.5	$18.1	$12.6
$31	$130.6	$128.5	$122.2	$115.9	$108.8	$101.6	$94.0	$86.3	$78.6	$71.0	$63.8	$56.5	$49.3	$42.0	$34.5	$26.9	$19.3	$13.5
$32	$136.0	$133.8	$127.3	$120.7	$113.4	$105.8	$98.0	$90.0	$82.0	$74.1	$66.6	$59.1	$51.6	$44.0	$36.2	$28.3	$20.4	$14.4
$33	$141.4	$139.0	$132.3	$125.5	$117.9	$110.1	$102.0	$93.7	$85.4	$77.3	$69.5	$61.7	$53.9	$46.0	$37.9	$29.7	$21.5	$15.3
$34	$146.7	$144.3	$137.3	$130.3	$122.5	$114.4	$106.0	$97.4	$88.9	$80.4	$72.3	$64.2	$56.2	$48.0	$39.6	$31.2	$22.6	$16.2
$35	$152.1	$149.6	$142.4	$135.0	$127.0	$118.6	$109.9	$101.1	$92.3	$83.5	$75.2	$66.8	$58.5	$50.0	$41.4	$32.6	$23.8	$17.1
$36	$157.5	$154.9	$147.4	$139.8	$131.5	$122.9	$113.9	$104.8	$95.7	$86.6	$78.0	$69.4	$60.8	$52.1	$43.1	$34.0	$24.9	$18.0
$37	$162.8	$160.1	$152.4	$144.6	$136.1	$127.2	$117.9	$108.5	$99.1	$89.8	$80.9	$72.0	$63.1	$54.1	$44.8	$35.4	$26.0	$18.9
$38	$168.2	$165.4	$157.5	$149.4	$140.6	$131.4	$121.9	$112.2	$102.5	$92.9	$83.8	$74.6	$65.4	$56.1	$46.5	$36.9	$27.1	$19.8
$39	$173.6	$170.7	$162.5	$154.2	$145.1	$135.7	$125.9	$115.9	$105.9	$96.0	$86.6	$77.1	$67.7	$58.1	$48.3	$38.3	$28.3	$20.7
$40	$178.9	$175.9	$167.6	$159.0	$149.7	$140.0	$129.9	$119.7	$109.4	$99.2	$89.5	$79.7	$70.0	$60.1	$50.0	$39.7	$29.4	$21.6

Table 9.2(e): Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ ($million) and Action Regions (t=12 yrs, $\mathcal{P}_1$=0 MSTB)

t=16 yrs | Produce | Abandon

Oil Price s ($/bbl)	Cumulative Secondary Oil $\mathcal{P}_2$ (MSTB) for Primary Oil $\mathcal{P}_1$=0 MSTB																			
	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9300
$0	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$1	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$2	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$3	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$4	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$5	-$1.8	-$1.2	-$1.3	-$1.3	-$1.5	-$1.7	-$2.0	-$2.2	-$2.4	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$6	$1.5	$2.0	$1.7	$1.4	$0.9	$0.5	-$0.1	-$0.6	-$1.1	-$1.5	-$1.8	-$2.1	-$2.3	-$2.4	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$7	$5.6	$6.0	$5.5	$5.0	$4.3	$3.5	$2.8	$2.0	$1.2	$0.5	-$0.1	-$0.6	-$1.0	-$1.5	-$1.9	-$2.3	-$2.5	-$2.6	-$2.6	-$2.6
$8	$10.2	$10.6	$8.8	$9.0	$8.1	$7.1	$6.0	$4.9	$3.9	$2.9	$2.1	$1.3	$0.5	-$0.2	-$0.9	-$1.6	-$2.2	-$2.6	-$2.6	-$2.6
$9	$15.1	$15.3	$14.3	$13.3	$12.1	$10.8	$9.5	$8.1	$6.8	$5.5	$4.4	$3.3	$2.3	$1.2	$0.2	-$0.8	-$1.7	-$2.4	-$2.6	-$2.6
$10	$20.1	$20.2	$19.0	$17.7	$16.2	$14.7	$13.0	$11.4	$9.8	$8.2	$6.8	$5.4	$4.1	$2.8	$1.5	$0.2	-$1.0	-$2.1	-$2.6	-$2.6
$11	$25.1	$25.2	$23.7	$22.2	$20.4	$18.6	$16.7	$14.8	$12.8	$11.0	$9.3	$7.7	$6.1	$4.5	$2.9	$1.3	-$0.3	-$1.7	-$2.6	-$2.6
$12	$30.2	$30.2	$28.5	$26.7	$24.7	$22.6	$20.4	$18.2	$16.0	$13.8	$11.8	$9.9	$8.0	$6.1	$4.2	$2.3	$0.4	-$1.4	-$2.6	-$2.6
$13	$35.4	$35.2	$33.2	$31.3	$29.0	$26.6	$24.1	$21.6	$19.1	$16.6	$14.4	$12.2	$10.0	$7.8	$5.6	$3.3	$1.1	-$1.0	-$2.6	-$2.6
$14	$40.5	$40.2	$38.0	$35.8	$33.3	$30.6	$27.9	$25.0	$22.2	$19.5	$16.9	$14.4	$12.0	$9.5	$6.9	$4.3	$1.8	-$0.7	-$2.6	-$2.6
$15	$45.6	$45.3	$42.8	$40.4	$37.6	$34.6	$31.6	$28.5	$25.4	$22.3	$19.5	$16.7	$13.9	$11.1	$8.3	$5.4	$2.5	-$0.2	-$2.5	-$2.5
$16	$50.8	$50.3	$47.6	$44.9	$41.8	$38.7	$35.3	$31.9	$28.5	$25.2	$22.1	$19.0	$15.9	$12.9	$9.7	$6.5	$3.4	$0.3	-$2.3	-$2.4
$17	$55.9	$55.4	$52.5	$49.5	$46.2	$42.7	$39.1	$35.4	$31.7	$28.1	$24.7	$21.3	$18.0	$14.6	$11.2	$7.7	$4.3	$0.9	-$2.0	-$2.3
$18	$61.1	$60.4	$57.3	$54.1	$50.5	$46.8	$42.9	$38.9	$34.9	$31.0	$27.4	$23.7	$20.1	$16.5	$12.8	$9.0	$5.2	$1.5	-$1.6	-$2.1
$19	$66.2	$65.5	$62.2	$58.7	$54.9	$50.9	$46.7	$42.5	$38.2	$34.0	$30.1	$26.2	$22.3	$18.4	$14.3	$10.3	$6.2	$2.2	-$1.3	-$2.0
$20	$71.4	$70.7	$67.1	$63.4	$59.3	$55.0	$50.8	$46.0	$41.5	$37.0	$32.8	$28.6	$24.5	$20.3	$15.9	$11.5	$7.2	$2.8	-$1.0	-$1.8
$21	$76.7	$75.8	$72.0	$68.1	$63.7	$59.2	$54.4	$49.6	$44.8	$40.0	$35.6	$31.1	$26.7	$22.1	$17.5	$12.8	$8.1	$3.5	-$0.6	-$1.6
$22	$81.9	$80.9	$76.9	$72.7	$68.1	$63.3	$58.3	$53.2	$48.1	$43.1	$38.3	$33.6	$28.9	$24.1	$19.1	$14.1	$9.1	$4.2	-$0.2	-$1.4
$23	$87.1	$86.1	$81.8	$77.4	$72.5	$67.5	$62.2	$56.8	$51.4	$46.1	$41.1	$36.0	$31.1	$26.0	$20.8	$15.5	$10.2	$4.9	$0.2	-$1.1
$24	$92.3	$91.2	$86.7	$82.1	$77.0	$71.6	$66.1	$60.4	$54.7	$49.1	$43.8	$38.5	$33.3	$27.9	$22.4	$16.8	$11.2	$5.7	$0.6	-$0.8
$25	$97.5	$96.4	$91.6	$86.8	$81.4	$75.8	$70.0	$64.0	$58.1	$52.2	$46.8	$41.0	$35.5	$29.9	$24.1	$18.2	$12.3	$6.4	$1.1	-$0.4
$26	$102.8	$101.5	$96.6	$91.5	$85.9	$80.0	$73.9	$67.7	$61.4	$55.3	$49.4	$43.6	$37.8	$31.8	$25.7	$19.6	$13.4	$7.2	$1.6	-$0.1
$27	$108.0	$106.7	$101.5	$96.2	$90.3	$84.2	$77.8	$71.3	$64.8	$58.3	$52.2	$46.1	$40.0	$33.8	$27.4	$21.0	$14.4	$8.0	$2.0	$0.2
$28	$113.2	$111.8	$106.4	$100.9	$94.8	$88.4	$81.7	$74.9	$68.1	$61.4	$55.0	$48.6	$42.3	$35.8	$29.1	$22.4	$15.5	$8.8	$2.5	$0.5
$29	$118.5	$117.0	$111.4	$105.6	$99.2	$92.6	$85.7	$78.6	$71.5	$64.5	$57.9	$51.2	$44.6	$37.8	$30.8	$23.8	$16.6	$9.5	$3.0	$0.8
$30	$123.7	$122.2	$116.3	$110.4	$103.7	$96.8	$89.6	$82.3	$74.9	$67.6	$60.7	$53.7	$46.8	$39.8	$32.5	$25.2	$17.7	$10.3	$3.4	$1.1
$31	$129.0	$127.4	$121.3	$115.1	$108.2	$101.0	$93.5	$85.9	$78.3	$70.7	$63.5	$56.3	$49.1	$41.8	$34.2	$26.6	$18.8	$11.1	$3.9	$1.4
$32	$134.2	$132.5	$126.2	$119.8	$112.7	$105.2	$97.5	$89.6	$81.6	$73.8	$66.3	$58.9	$51.4	$43.8	$35.9	$28.0	$19.9	$11.9	$4.4	$1.8
$33	$139.5	$137.7	$131.2	$124.5	$117.1	$109.4	$101.4	$93.2	$85.0	$76.9	$69.2	$61.4	$53.7	$45.8	$37.6	$29.4	$21.0	$12.7	$4.9	$2.1
$34	$144.7	$142.9	$136.1	$129.2	$121.6	$113.6	$105.3	$96.9	$88.4	$80.0	$72.0	$64.0	$56.0	$47.8	$39.4	$30.8	$22.1	$13.5	$5.3	$2.4
$35	$149.9	$148.1	$141.1	$134.0	$126.1	$117.8	$109.3	$100.5	$91.8	$83.1	$74.8	$66.5	$58.2	$49.8	$41.1	$32.2	$23.2	$14.2	$5.8	$2.7
$36	$155.2	$153.2	$146.0	$138.7	$130.5	$122.1	$113.2	$104.2	$95.1	$86.2	$77.6	$69.1	$60.5	$51.8	$42.8	$33.6	$24.3	$15.0	$6.3	$3.0
$37	$160.4	$158.4	$151.0	$143.4	$135.0	$126.3	$117.1	$107.8	$98.5	$89.3	$80.5	$71.6	$62.8	$53.8	$44.5	$35.0	$25.4	$15.8	$6.7	$3.3
$38	$165.7	$163.6	$155.9	$148.1	$139.5	$130.5	$121.1	$111.5	$101.9	$92.4	$83.3	$74.2	$65.1	$55.8	$46.2	$36.4	$26.5	$16.6	$7.2	$3.6
$39	$170.9	$168.7	$160.9	$152.9	$144.0	$134.7	$125.0	$115.2	$105.3	$95.5	$86.1	$76.7	$67.3	$57.7	$47.9	$37.8	$27.6	$17.4	$7.7	$3.9
$40	$176.2	$173.9	$165.8	$157.6	$148.4	$138.9	$128.9	$118.8	$108.6	$98.6	$88.9	$79.3	$69.6	$59.7	$49.6	$39.2	$28.7	$18.2	$8.2	$4.3

Table 9.2(f): Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ ($million) and Action Regions (t=16 yrs, $\mathcal{P}_1$=0 MSTB)

t=20 yrs | Produce | Abandon

Oil Price s ($/bbl)	Cumulative Secondary Oil $\mathcal{P}_2$ (MSTB) for Primary Oil $\mathcal{P}_1$=0 MSTB																				
	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	9745
$0	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$1	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$2	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$3	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$4	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$5	-$1.8	-$1.2	-$1.3	-$1.3	-$1.5	-$1.7	-$2.0	-$2.2	-$2.4	-$2.6	-$2.8	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$6	$1.5	$2.0	$1.7	$1.4	$0.9	$0.5	-$0.1	-$0.6	-$1.1	-$1.5	-$1.8	-$2.1	-$2.3	-$2.4	-$2.8	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$7	$5.6	$6.0	$5.5	$5.0	$4.3	$3.5	$2.8	$2.0	$1.2	$0.5	-$0.1	-$0.6	-$1.0	-$1.5	-$1.9	-$2.3	-$2.5	-$2.6	-$2.6	-$2.6	-$2.6
$8	$10.1	$10.5	$9.8	$9.0	$8.1	$7.1	$6.0	$4.9	$3.9	$2.9	$2.1	$1.3	$0.5	-$0.2	-$0.9	-$1.6	-$2.2	-$2.6	-$2.6	-$2.6	-$2.6
$9	$14.9	$15.2	$14.2	$13.2	$12.1	$10.8	$9.5	$8.1	$6.7	$5.5	$4.3	$3.3	$2.3	$1.2	$0.2	-$0.8	-$1.7	-$2.4	-$2.6	-$2.6	-$2.6
$10	$19.7	$20.0	$18.8	$17.6	$16.1	$14.6	$13.0	$11.4	$9.7	$8.2	$6.8	$5.4	$4.1	$2.8	$1.5	$0.2	-$1.0	-$2.1	-$2.6	-$2.6	-$2.6
$11	$24.5	$24.8	$23.4	$22.0	$20.3	$18.5	$16.6	$14.7	$12.8	$10.9	$9.3	$7.6	$6.1	$4.5	$2.9	$1.2	-$0.3	-$1.7	-$2.6	-$2.6	-$2.6
$12	$29.4	$29.6	$28.0	$26.4	$24.5	$22.4	$20.3	$18.1	$15.9	$13.8	$11.8	$9.9	$8.0	$6.1	$4.2	$2.3	$0.4	-$1.4	-$2.6	-$2.6	-$2.6
$13	$34.2	$34.5	$32.7	$30.8	$28.7	$26.4	$23.9	$21.5	$19.0	$16.6	$14.3	$12.1	$10.0	$7.8	$5.5	$3.3	$1.1	-$1.0	-$2.6	-$2.6	-$2.6
$14	$39.1	$39.3	$37.3	$35.3	$32.8	$30.3	$27.6	$24.8	$22.1	$19.4	$16.9	$14.4	$11.9	$9.5	$6.9	$4.3	$1.8	-$0.7	-$2.6	-$2.6	-$2.6
$15	$43.9	$44.2	$42.0	$39.7	$37.0	$34.2	$31.3	$28.2	$25.2	$22.2	$19.4	$16.6	$13.9	$11.1	$8.3	$5.4	$2.5	-$0.2	-$2.5	-$2.6	-$2.6
$16	$48.8	$49.0	$46.6	$44.1	$41.2	$38.2	$34.9	$31.6	$28.3	$25.0	$22.0	$18.9	$15.9	$12.8	$9.7	$6.5	$3.4	$0.3	-$2.3	-$2.6	-$2.6
$17	$53.7	$53.9	$51.3	$48.6	$45.4	$42.1	$38.6	$35.0	$31.4	$27.9	$24.6	$21.3	$18.0	$14.6	$11.2	$7.7	$4.3	$0.9	-$2.0	-$2.6	-$2.6
$18	$58.5	$58.7	$55.9	$53.0	$49.7	$46.1	$42.3	$38.5	$34.6	$30.8	$27.2	$23.6	$20.1	$16.5	$12.7	$9.0	$5.2	$1.5	-$1.7	-$2.6	-$2.6
$19	$63.4	$63.6	$60.6	$57.5	$53.9	$50.1	$46.1	$42.0	$37.8	$33.7	$29.9	$26.0	$22.2	$18.3	$14.3	$10.2	$6.2	$2.2	-$1.3	-$2.6	-$2.6
$20	$68.3	$68.5	$65.3	$62.0	$58.1	$54.1	$49.8	$45.4	$41.0	$36.7	$32.6	$28.4	$24.4	$20.2	$15.9	$11.5	$7.1	$2.8	-$1.0	-$2.6	-$2.6
$21	$73.2	$73.3	$70.0	$66.5	$62.4	$58.1	$53.6	$48.9	$44.2	$39.6	$35.3	$30.9	$26.5	$22.0	$17.4	$12.8	$8.1	$3.5	-$0.7	-$2.6	-$2.6
$22	$78.0	$78.2	$74.7	$71.0	$66.7	$62.1	$57.3	$52.4	$47.5	$42.6	$37.9	$33.3	$28.7	$23.9	$19.0	$14.1	$9.1	$4.2	-$0.3	-$2.5	-$2.6
$23	$82.9	$83.1	$79.3	$75.4	$70.9	$66.1	$61.1	$55.9	$50.7	$45.5	$40.6	$35.7	$30.8	$25.8	$20.6	$15.4	$10.1	$4.9	$0.1	-$2.3	-$2.6
$24	$87.8	$88.0	$84.0	$79.9	$75.2	$70.2	$64.8	$59.4	$53.9	$48.5	$43.3	$38.2	$33.0	$27.7	$22.3	$16.7	$11.1	$5.6	$0.5	-$2.2	-$2.6
$25	$92.7	$92.9	$88.7	$84.4	$79.4	$74.2	$68.6	$62.9	$57.1	$51.4	$46.0	$40.6	$35.2	$29.6	$23.9	$18.1	$12.2	$6.4	$1.0	-$2.0	-$2.6
$26	$97.6	$97.7	$93.4	$88.9	$83.7	$78.2	$72.4	$66.4	$60.4	$54.4	$48.8	$43.1	$37.4	$31.6	$25.6	$19.4	$13.3	$7.1	$1.4	-$1.8	-$2.6
$27	$102.4	$102.6	$98.1	$93.4	$88.0	$82.2	$76.1	$69.9	$63.6	$57.4	$51.5	$45.5	$39.6	$33.5	$27.2	$20.8	$14.3	$7.9	$1.9	-$1.7	-$2.6
$28	$107.3	$107.5	$102.8	$97.9	$92.2	$86.2	$79.9	$73.4	$66.9	$60.4	$54.2	$48.0	$41.8	$35.4	$28.9	$22.2	$15.4	$8.6	$2.3	-$1.5	-$2.6
$29	$112.2	$112.4	$107.5	$102.4	$96.5	$90.3	$83.7	$76.9	$70.1	$63.4	$57.0	$50.5	$44.0	$37.4	$30.5	$23.5	$16.5	$9.4	$2.8	-$1.3	-$2.6
$30	$117.1	$117.3	$112.2	$106.9	$100.8	$94.3	$87.5	$80.4	$73.4	$66.3	$59.7	$53.0	$46.2	$39.3	$32.2	$24.9	$17.5	$10.2	$3.3	-$1.2	-$2.6
$31	$122.0	$122.2	$116.9	$111.4	$105.0	$98.3	$91.2	$84.0	$76.6	$69.3	$62.4	$55.4	$48.5	$41.3	$33.9	$26.3	$18.6	$10.9	$3.7	-$1.0	-$2.6
$32	$126.8	$127.0	$121.6	$115.9	$109.3	$102.4	$95.0	$87.5	$79.9	$72.3	$65.2	$57.9	$50.7	$43.2	$35.5	$27.7	$19.7	$11.7	$4.2	-$0.8	-$2.6
$33	$131.7	$131.9	$126.3	$120.4	$113.6	$106.4	$98.8	$91.0	$83.1	$75.3	$67.9	$60.4	$52.9	$45.2	$37.2	$29.0	$20.8	$12.5	$4.6	-$0.7	-$2.6
$34	$136.6	$136.8	$131.0	$124.9	$117.9	$110.4	$102.6	$94.5	$86.4	$78.3	$70.6	$62.9	$55.1	$47.1	$38.8	$30.4	$21.8	$13.2	$5.1	-$0.5	-$2.6
$35	$141.5	$141.7	$135.7	$129.4	$122.1	$114.5	$106.3	$98.0	$89.6	$81.3	$73.3	$65.3	$57.3	$49.0	$40.5	$31.8	$22.9	$14.0	$5.5	-$0.3	-$2.6
$36	$146.4	$146.6	$140.4	$133.9	$126.4	$118.5	$110.1	$101.5	$92.9	$84.2	$76.1	$67.8	$59.5	$51.0	$42.2	$33.1	$24.0	$14.8	$6.0	-$0.2	-$2.6
$37	$151.3	$151.5	$145.1	$138.4	$130.7	$122.5	$113.9	$105.0	$96.1	$87.2	$78.8	$70.3	$61.7	$52.9	$43.8	$34.5	$25.0	$15.5	$6.5	$0.0	-$2.6
$38	$156.1	$156.4	$149.8	$142.9	$134.9	$126.5	$117.6	$108.5	$99.3	$90.2	$81.5	$72.8	$64.0	$54.9	$45.5	$35.9	$26.1	$16.3	$6.9	$0.2	-$2.6
$39	$161.0	$161.2	$154.5	$147.4	$139.2	$130.6	$121.4	$112.1	$102.6	$93.2	$84.3	$75.2	$66.2	$56.8	$47.2	$37.3	$27.2	$17.1	$7.4	$0.3	-$2.6
$40	$165.9	$166.1	$159.1	$151.9	$143.5	$134.6	$125.2	$115.6	$105.8	$96.2	$87.0	$77.7	$68.4	$58.8	$48.8	$38.6	$28.3	$17.8	$7.8	$0.5	-$2.6

Table 9.2(g): Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ ($million) and Action Regions (t=20 yrs, $\mathcal{P}_1$=0 MSTB)

t=24 yrs	Produce	Abandon

Oil Price s ($/bbl)	Cumulative Secondary Oil $\mathcal{P}_2$ (MSTB) for Primary Oil $\mathcal{P}_1$=0 MSTB																				
	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	9745
$0	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$1	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$2	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$3	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$4	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$5	-$1.8	-$1.2	-$1.3	-$1.3	-$1.5	-$1.7	-$2.0	-$2.2	-$2.4	-$2.6	-$2.8	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$6	$1.4	$2.0	$1.7	$1.4	$0.9	$0.5	-$0.1	-$0.6	-$1.1	-$1.5	-$1.8	-$2.1	-$2.3	-$2.4	-$2.8	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$7	$5.2	$5.8	$5.3	$4.8	$4.2	$3.5	$2.7	$1.9	$1.2	$0.5	-$0.1	-$0.6	-$1.1	-$1.5	-$1.9	-$2.3	-$2.5	-$2.6	-$2.6	-$2.6	-$2.6
$8	$9.2	$9.9	$9.3	$8.6	$7.8	$6.9	$5.8	$4.8	$3.8	$2.8	$2.0	$1.2	$0.5	-$0.2	-$0.9	-$1.6	-$2.2	-$2.6	-$2.6	-$2.6	-$2.6
$9	$13.2	$14.0	$13.3	$12.5	$11.4	$10.3	$9.1	$7.8	$6.5	$5.3	$4.3	$3.2	$2.2	$1.2	$0.2	-$0.8	-$1.7	-$2.4	-$2.6	-$2.6	-$2.6
$10	$17.2	$18.2	$17.3	$16.3	$15.1	$13.8	$12.3	$10.8	$9.3	$7.9	$6.6	$5.3	$4.1	$2.8	$1.5	$0.2	-$1.0	-$2.1	-$2.6	-$2.6	-$2.6
$11	$21.3	$22.3	$21.3	$20.2	$18.8	$17.3	$15.6	$13.9	$12.2	$10.5	$9.0	$7.4	$5.9	$4.4	$2.8	$1.2	-$0.3	-$1.7	-$2.6	-$2.6	-$2.6
$12	$25.3	$26.4	$25.3	$24.1	$22.5	$20.8	$18.9	$17.0	$15.0	$13.1	$11.3	$9.6	$7.8	$6.0	$4.1	$2.3	$0.4	-$1.4	-$2.6	-$2.6	-$2.6
$13	$29.3	$30.6	$29.3	$27.9	$26.2	$24.3	$22.2	$20.0	$17.8	$15.7	$13.7	$11.7	$9.7	$7.6	$5.5	$3.3	$1.1	-$1.0	-$2.6	-$2.6	-$2.6
$14	$33.3	$34.7	$33.3	$31.8	$29.9	$27.8	$25.5	$23.1	$20.7	$18.3	$16.1	$13.9	$11.6	$9.3	$6.8	$4.3	$1.8	-$0.7	-$2.6	-$2.6	-$2.6
$15	$37.3	$38.8	$37.3	$35.7	$33.6	$31.3	$28.8	$26.2	$23.5	$20.9	$18.5	$16.0	$13.5	$10.9	$8.1	$5.3	$2.5	-$0.2	-$2.5	-$2.6	-$2.6
$16	$41.3	$42.9	$41.3	$39.5	$37.3	$34.8	$32.1	$29.2	$26.4	$23.5	$20.9	$18.2	$15.4	$12.6	$9.5	$6.4	$3.3	$0.3	-$2.3	-$2.6	-$2.6
$17	$45.4	$47.1	$45.3	$43.4	$41.0	$38.3	$35.4	$32.3	$29.2	$26.1	$23.3	$20.4	$17.4	$14.3	$11.0	$7.6	$4.2	$0.9	-$2.0	-$2.6	-$2.6
$18	$49.4	$51.2	$49.3	$47.3	$44.6	$41.8	$38.7	$35.4	$32.1	$28.8	$25.7	$22.6	$19.4	$16.0	$12.5	$8.8	$5.1	$1.5	-$1.7	-$2.6	-$2.6
$19	$53.4	$55.3	$53.3	$51.1	$48.3	$45.3	$42.0	$38.5	$34.9	$31.4	$28.2	$24.8	$21.4	$17.8	$14.0	$10.0	$6.0	$2.1	-$1.4	-$2.6	-$2.6
$20	$57.4	$59.5	$57.3	$55.0	$52.0	$48.8	$45.3	$41.6	$37.8	$34.1	$30.6	$27.0	$23.4	$19.5	$15.4	$11.2	$7.0	$2.7	-$1.1	-$2.6	-$2.6
$21	$61.4	$63.6	$61.3	$58.9	$55.7	$52.3	$48.6	$44.6	$40.7	$36.7	$33.0	$29.3	$25.4	$21.3	$16.9	$12.5	$7.9	$3.4	-$0.7	-$2.6	-$2.6
$22	$65.4	$67.7	$65.3	$62.7	$59.4	$55.8	$51.9	$47.7	$43.5	$39.4	$35.5	$31.5	$27.4	$23.0	$18.4	$13.7	$8.8	$4.0	-$0.4	-$2.5	-$2.6
$23	$69.4	$71.9	$69.3	$66.6	$63.1	$59.3	$55.2	$50.8	$46.4	$42.0	$37.9	$33.7	$29.4	$24.8	$19.9	$14.9	$9.8	$4.7	$0.0	-$2.3	-$2.6
$24	$73.5	$76.0	$73.3	$70.5	$66.8	$62.8	$58.5	$53.9	$49.3	$44.7	$40.4	$35.9	$31.4	$26.6	$21.5	$16.2	$10.8	$5.4	$0.4	-$2.2	-$2.6
$25	$77.5	$80.1	$77.3	$74.4	$70.5	$66.4	$61.8	$57.0	$52.1	$47.3	$42.8	$38.2	$33.4	$28.4	$23.0	$17.4	$11.8	$6.1	$0.8	-$2.0	-$2.6
$26	$81.5	$84.3	$81.3	$78.2	$74.2	$69.9	$65.1	$60.1	$55.0	$50.0	$45.3	$40.4	$35.4	$30.1	$24.5	$18.7	$12.8	$6.8	$1.3	-$1.8	-$2.6
$27	$85.5	$88.4	$85.3	$82.1	$77.9	$73.4	$68.4	$63.2	$57.9	$52.6	$47.7	$42.6	$37.4	$31.9	$26.1	$20.0	$13.8	$7.5	$1.7	-$1.7	-$2.6
$28	$89.5	$92.5	$89.3	$86.0	$81.6	$76.9	$71.7	$66.3	$60.7	$55.3	$50.2	$44.9	$39.5	$33.7	$27.6	$21.3	$14.7	$8.2	$2.1	-$1.5	-$2.6
$29	$93.5	$96.7	$93.3	$89.8	$85.3	$80.4	$75.0	$69.3	$63.6	$57.9	$52.6	$47.1	$41.5	$35.5	$29.1	$22.5	$15.7	$8.9	$2.5	-$1.3	-$2.6
$30	$97.6	$100.8	$97.3	$93.7	$89.0	$83.9	$78.3	$72.4	$66.5	$60.6	$55.1	$49.3	$43.5	$37.3	$30.7	$23.8	$16.7	$9.6	$3.0	-$1.2	-$2.6
$31	$101.6	$104.9	$101.4	$97.6	$92.7	$87.4	$81.6	$75.5	$69.4	$63.2	$57.5	$51.6	$45.5	$39.0	$32.2	$25.1	$17.7	$10.3	$3.4	-$1.0	-$2.6
$32	$105.6	$109.1	$105.4	$101.4	$96.4	$90.9	$84.9	$78.6	$72.2	$65.9	$60.0	$53.8	$47.5	$40.8	$33.7	$26.3	$18.7	$11.0	$3.8	-$0.9	-$2.6
$33	$109.6	$113.2	$109.4	$105.3	$100.1	$94.4	$88.2	$81.7	$75.1	$68.5	$62.4	$56.0	$49.5	$42.6	$35.3	$27.6	$19.7	$11.8	$4.2	-$0.7	-$2.6
$34	$113.6	$117.3	$113.4	$109.2	$103.8	$97.9	$91.5	$84.8	$78.0	$71.2	$64.8	$58.3	$51.6	$44.4	$36.8	$28.9	$20.7	$12.5	$4.6	-$0.5	-$2.6
$35	$117.6	$121.4	$117.4	$113.1	$107.5	$101.5	$94.8	$87.9	$80.8	$73.8	$67.3	$60.5	$53.6	$46.2	$38.3	$30.1	$21.7	$13.2	$5.1	-$0.4	-$2.6
$36	$121.6	$125.6	$121.4	$116.9	$111.2	$105.0	$98.1	$91.0	$83.7	$76.5	$69.7	$62.8	$55.6	$48.0	$39.8	$31.4	$22.7	$13.9	$5.5	-$0.2	-$2.6
$37	$125.7	$129.7	$125.4	$120.8	$114.9	$108.5	$101.4	$94.1	$86.6	$79.1	$72.2	$65.0	$57.6	$49.7	$41.4	$32.7	$23.7	$14.6	$5.9	$0.0	-$2.6
$38	$129.7	$133.8	$129.4	$124.7	$118.6	$112.0	$104.7	$97.1	$89.4	$81.8	$74.6	$67.2	$59.6	$51.5	$42.9	$33.9	$24.7	$15.3	$6.3	$0.1	-$2.6
$39	$133.7	$138.0	$133.4	$128.5	$122.3	$115.5	$108.0	$100.2	$92.3	$84.4	$77.1	$69.5	$61.6	$53.3	$44.4	$35.2	$25.7	$16.0	$6.8	$0.3	-$2.6
$40	$137.7	$142.1	$137.4	$132.4	$126.0	$119.0	$111.3	$103.3	$95.2	$87.1	$79.5	$71.7	$63.7	$55.1	$46.0	$36.5	$26.7	$16.7	$7.2	$0.4	-$2.6

Table 9.2(h): Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ ($million) and Action Regions (t=24 yrs, $\mathcal{P}_1$=0 MSTB)

t=28 yrs	Produce	Abandon

Oil Price s ($/bbl)	Cumulative Secondary Oil $\mathcal{P}_2$ (MSTB) for Primary Oil $\mathcal{P}_1$=0 MSTB																				
	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	9745
$0	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$1	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$2	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$3	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$4	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$5	-$2.0	-$1.3	-$1.3	-$1.4	-$1.5	-$1.7	-$2.0	-$2.2	-$2.4	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$6	$0.3	$1.3	$1.2	$1.0	$0.7	$0.3	-$0.2	-$0.7	-$1.1	-$1.6	-$1.8	-$2.1	-$2.3	-$2.4	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$7	$2.6	$3.9	$3.8	$3.6	$3.1	$2.6	$2.0	$1.3	$0.7	$0.1	-$0.3	-$0.8	-$1.1	-$1.5	-$1.9	-$2.3	-$2.6	-$2.6	-$2.6	-$2.6	-$2.6
$8	$4.9	$6.6	$6.4	$6.1	$5.6	$4.9	$4.1	$3.3	$2.6	$1.8	$1.3	$0.7	$0.2	-$0.4	-$1.0	-$1.6	-$2.2	-$2.6	-$2.6	-$2.6	-$2.6
$9	$7.3	$9.2	$9.0	$8.7	$8.0	$7.2	$6.3	$5.4	$4.4	$3.6	$2.9	$2.2	$1.6	$0.9	$0.0	-$0.8	-$1.7	-$2.4	-$2.6	-$2.6	-$2.6
$10	$9.6	$11.9	$11.6	$11.2	$10.5	$9.6	$8.5	$7.4	$6.3	$5.3	$4.5	$3.8	$3.0	$2.1	$1.1	$0.0	-$1.1	-$2.1	-$2.6	-$2.6	-$2.6
$11	$11.9	$14.5	$14.2	$13.8	$12.9	$11.9	$10.7	$9.4	$8.2	$7.0	$6.2	$5.3	$4.4	$3.4	$2.2	$0.9	-$0.4	-$1.8	-$2.6	-$2.6	-$2.6
$12	$14.3	$17.2	$16.8	$16.3	$15.4	$14.2	$12.8	$11.5	$10.1	$8.8	$7.8	$6.8	$5.8	$4.7	$3.3	$1.8	$0.2	-$1.4	-$2.6	-$2.6	-$2.6
$13	$16.6	$19.8	$19.4	$18.9	$17.8	$16.5	$15.0	$13.5	$12.0	$10.5	$9.4	$8.3	$7.2	$6.0	$4.4	$2.7	$0.8	-$1.1	-$2.6	-$2.6	-$2.6
$14	$18.9	$22.4	$22.0	$21.5	$20.3	$18.8	$17.2	$15.5	$13.8	$12.3	$11.1	$9.9	$8.7	$7.2	$5.5	$3.6	$1.4	-$0.8	-$2.6	-$2.6	-$2.6
$15	$21.3	$25.1	$24.8	$24.0	$22.7	$21.2	$19.4	$17.5	$15.7	$14.0	$12.7	$11.4	$10.1	$8.5	$6.6	$4.5	$2.1	-$0.4	-$2.5	-$2.6	-$2.6
$16	$23.6	$27.7	$27.3	$26.6	$25.2	$23.5	$21.8	$19.6	$17.6	$15.8	$14.4	$12.9	$11.5	$9.8	$7.7	$5.4	$2.8	$0.1	-$2.3	-$2.6	-$2.6
$17	$26.0	$30.4	$29.9	$29.1	$27.6	$25.8	$23.7	$21.6	$19.5	$17.5	$16.0	$14.5	$12.9	$11.1	$8.9	$6.4	$3.6	$0.6	-$2.1	-$2.6	-$2.6
$18	$28.3	$33.0	$32.5	$31.7	$30.1	$28.1	$25.9	$23.6	$21.4	$19.2	$17.6	$16.0	$14.3	$12.4	$10.0	$7.3	$4.3	$1.1	-$1.8	-$2.6	-$2.6
$19	$30.6	$35.7	$35.1	$34.2	$32.5	$30.5	$28.1	$25.7	$23.2	$21.0	$19.3	$17.5	$15.8	$13.7	$11.1	$8.3	$5.0	$1.6	-$1.6	-$2.6	-$2.6
$20	$33.0	$38.3	$37.7	$36.8	$35.0	$32.8	$30.3	$27.7	$25.1	$22.7	$20.9	$19.1	$17.2	$15.0	$12.3	$9.2	$5.8	$2.1	-$1.3	-$2.6	-$2.6
$21	$35.3	$40.9	$40.3	$39.3	$37.4	$35.1	$32.5	$29.7	$27.0	$24.5	$22.5	$20.6	$18.6	$16.3	$13.4	$10.2	$6.5	$2.6	-$1.1	-$2.6	-$2.6
$22	$37.6	$43.6	$42.9	$41.9	$39.8	$37.4	$34.8	$31.7	$28.9	$26.2	$24.2	$22.1	$20.0	$17.5	$14.5	$11.1	$7.2	$3.1	-$0.8	-$2.5	-$2.6
$23	$40.0	$46.2	$45.5	$44.4	$42.3	$39.8	$36.8	$33.8	$30.8	$28.0	$25.8	$23.6	$21.4	$18.8	$15.7	$12.1	$8.0	$3.6	-$0.5	-$2.3	-$2.6
$24	$42.3	$48.9	$48.1	$47.0	$44.7	$42.1	$39.0	$35.8	$32.6	$29.7	$27.5	$25.2	$22.9	$20.1	$16.8	$13.0	$8.8	$4.2	-$0.2	-$2.2	-$2.6
$25	$44.6	$51.5	$50.7	$49.6	$47.2	$44.4	$41.2	$37.8	$34.5	$31.5	$29.1	$26.7	$24.3	$21.4	$18.0	$14.0	$9.5	$4.7	$0.2	-$2.1	-$2.6
$26	$47.0	$54.2	$53.3	$52.1	$49.6	$46.7	$43.4	$39.9	$36.4	$33.2	$30.7	$28.2	$25.7	$22.7	$19.1	$14.9	$10.3	$5.2	$0.5	-$1.9	-$2.6
$27	$49.3	$56.8	$55.9	$54.7	$52.1	$49.1	$45.5	$41.9	$38.3	$34.9	$32.4	$29.8	$27.1	$24.0	$20.2	$15.9	$11.0	$5.8	$0.8	-$1.8	-$2.6
$28	$51.7	$59.5	$58.6	$57.2	$54.5	$51.4	$47.7	$43.9	$40.2	$36.7	$34.0	$31.3	$28.6	$25.3	$21.4	$16.9	$11.8	$6.3	$1.1	-$1.6	-$2.6
$29	$54.0	$62.1	$61.2	$59.8	$57.0	$53.7	$49.9	$45.9	$42.0	$38.4	$35.7	$32.8	$30.0	$26.6	$22.5	$17.8	$12.5	$6.8	$1.4	-$1.5	-$2.6
$30	$56.3	$64.7	$63.8	$62.3	$59.4	$56.0	$52.1	$48.0	$43.9	$40.2	$37.3	$34.4	$31.4	$27.9	$23.6	$18.8	$13.3	$7.4	$1.7	-$1.4	-$2.6
$31	$58.7	$67.4	$66.4	$64.9	$61.9	$58.4	$54.2	$50.0	$45.8	$41.9	$38.9	$35.9	$32.8	$29.2	$24.8	$19.7	$14.0	$7.9	$2.0	-$1.2	-$2.6
$32	$61.0	$70.0	$69.0	$67.4	$64.3	$60.7	$56.4	$52.0	$47.7	$43.7	$40.6	$37.4	$34.2	$30.5	$25.9	$20.7	$14.8	$8.4	$2.3	-$1.1	-$2.6
$33	$63.3	$72.7	$71.6	$70.0	$66.8	$63.0	$58.6	$54.1	$49.6	$45.4	$42.2	$38.9	$35.7	$31.8	$27.1	$21.6	$15.5	$9.0	$2.6	-$0.9	-$2.6
$34	$65.7	$75.3	$74.2	$72.5	$69.2	$65.3	$60.8	$56.1	$51.5	$47.1	$43.8	$40.5	$37.1	$33.1	$28.2	$22.6	$16.3	$9.5	$2.9	-$0.8	-$2.6
$35	$68.0	$78.0	$76.8	$75.1	$71.7	$67.6	$63.0	$58.1	$53.3	$48.9	$45.5	$42.0	$38.5	$34.4	$29.3	$23.6	$17.1	$10.0	$3.2	-$0.7	-$2.6
$36	$70.3	$80.6	$79.4	$77.7	$74.1	$70.0	$65.1	$60.1	$55.2	$50.6	$47.1	$43.5	$39.9	$35.6	$30.5	$24.5	$17.8	$10.6	$3.6	-$0.5	-$2.6
$37	$72.7	$83.3	$82.0	$80.2	$76.6	$72.3	$67.3	$62.2	$57.1	$52.4	$48.8	$45.1	$41.4	$36.9	$31.6	$25.5	$18.6	$11.1	$3.9	-$0.4	-$2.6
$38	$75.0	$85.9	$84.6	$82.8	$79.0	$74.6	$69.5	$64.2	$59.0	$54.1	$50.4	$46.6	$42.8	$38.2	$32.7	$26.4	$19.3	$11.6	$4.2	-$0.2	-$2.6
$39	$77.4	$88.5	$87.2	$85.3	$81.5	$76.9	$71.7	$66.2	$60.9	$55.9	$52.0	$48.1	$44.2	$39.5	$33.9	$27.4	$20.1	$12.2	$4.5	-$0.1	-$2.6
$40	$79.7	$91.2	$89.8	$87.9	$83.9	$79.3	$73.9	$68.3	$62.7	$57.6	$53.7	$49.7	$45.6	$40.8	$35.0	$28.3	$20.8	$12.7	$4.8	$0.0	-$2.6

Table 9.2(i): Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ ($million) and Action Regions (t=28 yrs, $\mathcal{P}_1$=0 MSTB)

Primary Oil $\mathcal{P}_1$ (MSTB)	time t (yrs) 0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
0	$6.25	$6.25	$6.25	$6.25	$6.25	$6.25	$6.25	$6.25	$6.25	$6.25	$6.25	$6.25	$6.25	$6.25	$6.25	$6.25
100		$7.75	$7.75	$7.75	$7.75	$7.75	$7.75	$7.75	$7.75	$7.75	$7.75	$7.75	$7.75	$7.75	$7.75	$7.75
200		$7.75	$9.75	$9.75	$9.75	$9.75	$9.75	$9.75	$9.75	$9.75	$9.75	$9.75	$9.75	$9.75	$9.75	$9.75
300			$9.75	$10.25	$10.25	$10.25	$10.25	$10.25	$10.25	$10.25	$10.25	$10.25	$10.25	$10.25	$10.25	$10.25
400				$10.25	$10.75	$10.75	$10.75	$11.00	$11.00	$10.75	$10.75	$10.75	$10.75	$11.00	$11.00	$11.00
500					$10.75	$11.00	$11.75	$11.75	$11.75	$11.75	$11.75	$11.75	$11.75	$11.75	$11.75	$11.75
600							$11.75	$13.25	$13.25	$13.25	$13.25	$13.25	$13.25	$13.25	$13.25	$13.25
700								$13.75	$13.75	$13.75	$14.00	$14.00	$14.00	$14.00	$14.00	$14.00
800										$14.75	$14.50	$14.50	$14.50	$14.75	$14.75	$14.75
900												$18.00				

Primary Oil $\mathcal{P}_1$ (MSTB)	time t (yrs) 16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
0	$6.25	$6.25	$6.25	$6.25	$6.25	$6.25	$6.25	$6.25	$6.25	$6.25	$6.25	$6.25	$6.25	$6.25	$6.25	$6.25
100	$7.75	$7.75	$7.75	$7.75	$7.75	$7.75	$7.75	$7.75	$7.75	$7.75	$7.75	$7.75	$7.75	$7.75	$7.75	$7.75
200	$9.75	$9.75	$9.75	$9.75	$9.75	$9.75	$9.75	$9.75	$9.75	$9.75	$9.75	$9.75	$9.75	$9.75	$9.75	$9.75
300	$10.25	$10.25	$10.25	$10.25	$10.25	$10.25	$10.25	$10.25	$10.25	$10.25	$10.25	$10.25	$10.25	$10.25	$10.25	$10.25
400	$10.75	$10.75	$10.75	$11.00	$11.00	$11.00	$11.00	$11.00	$10.75	$11.00	$10.75	$10.75	$10.75	$10.75	$10.75	$10.75
500	$11.75	$11.75	$11.75	$11.75	$11.75	$11.75	$11.75	$11.75	$11.75	$11.75	$11.75	$11.75	$11.75	$11.75	$11.75	$11.75
600	$13.25	$13.25	$13.25	$13.50	$13.50	$13.75	$13.75	$14.00	$14.00	$14.00	$14.00	$14.00	$14.00	$14.00	$14.00	$14.00
700	$14.00	$14.00	$14.00	$14.25	$14.25	$14.50	$14.75	$15.25	$16.00	$17.00	$17.50	$17.50	$17.50	$17.50	$17.50	$17.50
800	$14.75	$14.75	$14.75	$15.00	$15.25	$15.50	$15.75	$16.50	$17.25	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00
900																

Table 9.3: Primary Economic Limit Abandonment Price $s_{1A}(\mathcal{P}_1,t)$ ($/bbl)

t=0 yrs																					
Primary Oil	Secondary Oil $\mathcal{P}_2$ (MSTB)																				
$\mathcal{P}_1$ (MSTB)	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50																				
100																					
200																					
300																					
400																					
500																					
600																					
700																					
800																					

t=1 yrs																					
Primary Oil	Secondary Oil $\mathcal{P}_2$ (MSTB)																				
$\mathcal{P}_1$ (MSTB)	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25																			
100	$4.50	$4.50																			
200																					
300																					
400																					
500																					
600																					
700																					
800																					

t=2 yrs																					
Primary Oil	Secondary Oil $\mathcal{P}_2$ (MSTB)																				
$\mathcal{P}_1$ (MSTB)	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25	$4.25	$4.00																	
100	$4.50	$4.25	$4.25																		
200	$4.50	$4.50																			
300																					
400																					
500																					
600																					
700																					
800																					

t=3 yrs																					
Primary Oil	Secondary Oil $\mathcal{P}_2$ (MSTB)																				
$\mathcal{P}_1$ (MSTB)	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00															
100	$4.50	$4.25	$4.25	$4.00	$4.00																
200	$4.50	$4.25	$4.25																		
300	$4.75	$4.50																			
400																					
500																					
600																					
700																					
800																					

Table 9.4: Secondary Economic Limit Abandonment Price $s_{2A}(\mathcal{P}_2,t;\mathcal{P}_1)$ (\$/bbl)

t=4 yrs																					
Primary Oil $\mathcal{P}_1$ (MSTB)	Secondary Oil $\mathcal{P}_2$ (MSTB)																				
	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25													
100	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00														
200	$4.50	$4.25	$4.25	$4.00	$4.00																
300	$4.75	$4.25	$4.25																		
400	$4.75	$4.75																			
500																					
600																					
700																					
800																					

t=5 yrs																					
Primary Oil $\mathcal{P}_1$ (MSTB)	Secondary Oil $\mathcal{P}_2$ (MSTB)																				
	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.25	$4.25											
100	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.25												
200	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00														
300	$4.75	$4.25	$4.25	$4.00																	
400	$4.75	$4.25																			
500																					
600																					
700																					
800																					

t=6 yrs																					
Primary Oil $\mathcal{P}_1$ (MSTB)	Secondary Oil $\mathcal{P}_2$ (MSTB)																				
	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.25	$4.75	$4.75	$4.75									
100	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$4.75										
200	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.25												
300	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00															
400	$4.75	$4.25	$4.25	$4.25																	
500	$4.75	$4.50																			
600																					
700																					
800																					

t=7 yrs																					
Primary Oil $\mathcal{P}_1$ (MSTB)	Secondary Oil $\mathcal{P}_2$ (MSTB)																				
	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.25	$4.75	$4.75	$5.00	$5.00								
100	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00									
200	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$4.75										
300	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.25												
400	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00															
500	$4.75	$4.25	$4.25																		
600	$5.00	$5.00																			
700																					
800																					

Table 9.4: Secondary Economic Limit Abandonment Price $s_{2A}(\mathcal{P}_2,t;\mathcal{P}_1)$ (\$/bbl) (continued)

t=8 yrs	Secondary Oil $\mathcal{P}_2$ (MSTB)																			
Primary Oil $\mathcal{P}_1$ (MSTB)	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.25	$4.75	$4.75	$5.00	$5.25	$5.25							
100	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25								
200	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00									
300	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.75	$4.75											
400	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.25													
500	$4.75	$4.25	$4.25	[illegible]	$4.00																
600	[illegible]	[illegible]																			
700																					
800																					

t=9 yrs	Secondary Oil $\mathcal{P}_2$ (MSTB)																			
Primary Oil $\mathcal{P}_1$ (MSTB)	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.25	$4.75	$4.75	$5.00	$5.25	$5.25	$5.25						
100	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.50						
200	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25								
300	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	[illegible]	$5.00									
400	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	[illegible]	$4.75	$4.75											
500	$4.75	$4.25	$4.25	$4.00	[illegible]	[illegible]	[illegible]														
600	$5.00	$4.25	$4.25	$4.25																	
700	[illegible]	[illegible]																			
800																					

t=10 yrs	Secondary Oil $\mathcal{P}_2$ (MSTB)																			
Primary Oil $\mathcal{P}_1$ (MSTB)	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25	$4.25	[illegible]	[illegible]	[illegible]	[illegible]	$4.25	$4.25	$4.75	$4.75	$5.00	$5.25	$5.25	$5.50	[illegible]	[illegible]				
100	$4.50	$4.25	$4.25	[illegible]	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$5.75					
200	$4.50	$4.25	$4.25	[illegible]	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.25							
300	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.25	$5.25								
400	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	[illegible]	[illegible]										
500	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.75	$4.75	$4.75												
600	$5.00	$4.25	[illegible]	[illegible]	[illegible]	[illegible]															
700	[illegible]	[illegible]																			
800																					

t=11 yrs	Secondary Oil $\mathcal{P}_2$ (MSTB)																			
Primary Oil $\mathcal{P}_1$ (MSTB)	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.25	$4.75	$4.75	$5.00	$5.25	$5.25	$5.50	$6.00	$6.00				
100	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.00	[illegible]				
200	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	[illegible]	$5.75	$5.75					
300	$4.75	[illegible]	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.25	$5.25	$5.25							
400	$4.75	[illegible]	$4.25	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	[illegible]	[illegible]									
500	$4.75	[illegible]	$4.25	$4.00	$4.00	$4.00	$4.25	$4.75	[illegible]	[illegible]											
600	[illegible]	$4.25	$4.25	$4.00	[illegible]	[illegible]	[illegible]	[illegible]													
700	$5.25	$4.50	[illegible]	[illegible]																	
800	[illegible]	[illegible]																			

Table 9.4: Secondary Economic Limit Abandonment Price $s_{2A}(\mathcal{P}_2,t;\mathcal{P}_1)$ ($/bbl) (continued)

t=12 yrs																				
Primary Oil	Secondary Oil $\mathcal{P}_2$ (MSTB)																			
$\mathcal{P}_1$ (MSTB)	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.25	$4.75	$4.75	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$6.50			
100	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.00	$6.75	$6.75			
200	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.25	$6.25				
300	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$5.50						
400	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.25							
500	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.00	$5.25									
600	$5.00	$4.25	$4.25	$4.00	$4.00	$4.25	$4.50	$4.75	$4.75												
700	$5.25	$4.50	$4.50	$4.25	$4.25	$4.50															
800	$5.50	$5.00																			

t=13 yrs																				
Primary Oil	Secondary Oil $\mathcal{P}_2$ (MSTB)																			
$\mathcal{P}_1$ (MSTB)	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.25	$4.75	$4.75	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.00	$8.00		
100	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.00	$6.75	$6.75			
200	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.25	$6.25				
300	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.00					
400	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.75	$5.75						
500	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.00	$5.25	$5.25								
600	$5.00	$4.25	$4.25	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.00										
700	$5.25	$4.50	$4.50	$4.25	$4.25	$4.50	$4.50														
800	$5.50	$4.75	$4.75																		

t=14 yrs																				
Primary Oil	Secondary Oil $\mathcal{P}_2$ (MSTB)																			
$\mathcal{P}_1$ (MSTB)	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.25	$4.75	$4.75	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.00	$14.00	$14.00	
100	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.00	$6.75	$9.50	$9.50		
200	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.25	$7.25	$7.25			
300	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$6.50				
400	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.75	$6.00	$6.00					
500	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$5.50							
600	$5.00	$4.25	$4.25	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25									
700	$5.25	$4.50	$4.50	$4.25	$4.25	$4.50	$4.75	$5.00	$5.00												
800	$5.50	$4.75	$4.50	$4.75	$4.75																

t=15 yrs																				
Primary Oil	Secondary Oil $\mathcal{P}_2$ (MSTB)																			
$\mathcal{P}_1$ (MSTB)	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.25	$4.75	$4.75	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.00	$14.00	$14.00	
100	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.00	$6.75	$9.50	$9.50		
200	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.25	$7.25	$11.50	$11.50		
300	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.50	$8.50			
400	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.75	$6.00	$6.75	$6.75				
500	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$5.75	$5.75						
600	$5.00	$4.25	$4.25	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.25								
700	$5.25	$4.50	$4.50	$4.25	$4.25	$4.50	$4.75	$5.00	$5.00	$5.00											
800	$5.50	$4.75	$4.50	$4.75	$4.75	$4.75															

Table 9.4: Secondary Economic Limit Abandonment Price $s_{2A}(\mathcal{P}_2,t;\mathcal{P}_1)$ (\$/bbl) (continued)

t=16 yrs

Primary Oil $\mathcal{P}_1$ (MSTB)	Secondary Oil $\mathcal{P}_2$ (MSTB)																				
	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.25	$4.75	$4.75	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.00	$14.00	$14.00	
100	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.00	$6.75	$9.50	$14.75	$14.75	
200	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.25	$7.25	$11.50	$11.50		
300	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.50	$8.50			
400	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.75	$6.00	$6.75	$6.75				
500	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$5.75	$6.50	$6.50					
600	$5.00	$4.25	$4.25	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$5.50							
700	$5.25	$4.50	$4.50	$4.25	$4.25	$4.50	$4.75	$5.[illegible]	$5.[illegible]	$5.[illegible]	$5.[illegible]										
800	$5.50	$4.75	$4.50	$4.75	$4.75	$4.75	$4.75														

t=17 yrs

Primary Oil $\mathcal{P}_1$ (MSTB)	Secondary Oil $\mathcal{P}_2$ (MSTB)																				
	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.25	$4.75	$4.75	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.00	$14.00	$14.00	
100	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.00	$6.75	$9.50	$14.75	$14.75	
200	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.25	$7.25	$11.50	$11.50		
300	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.50	$14.25	$14.25		
400	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.75	$6.00	$6.75	$9.75	$9.75			
500	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$5.75	$6.50	$8.[illegible]	$8.00				
600	$5.00	$4.25	$4.25	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.[illegible]	$6.[illegible]						
700	$5.25	$4.50	$4.50	$4.25	$4.25	$4.50	$4.75	$5.00	$5.00	$5.[illegible]	$5.25	$5.50	$5.50								
800	$5.50	$4.75	$4.50	$4.75	$4.75	$4.75	$4.75	$5.[illegible]	$5.[illegible]												

t=18 yrs

Primary Oil $\mathcal{P}_1$ (MSTB)	Secondary Oil $\mathcal{P}_2$ (MSTB)																				
	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.25	$4.75	$4.75	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.00	$14.00	$20.00	$20.00
100	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.00	$6.75	$9.50	$14.75	$15.00	
200	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.25	$7.25	$11.50	$18.75	$18.75	
300	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.50	$14.25	$14.25		
400	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.75	$6.00	$6.75	$9.75	$9.75			
500	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$5.75	$6.50	$8.00	$9.[illegible]				
600	$5.00	$4.25	$4.25	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.75	$6.75					
700	$5.25	$4.50	$4.50	$4.25	$4.25	$4.50	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$6.[illegible]	$6.[illegible]							
800	[illegible]	[illegible]	$4.[illegible]	$4.75	$4.75	$4.75	$4.75	$5.[illegible]	$5.[illegible]	$5.[illegible]											

t=19 yrs

Primary Oil $\mathcal{P}_1$ (MSTB)	Secondary Oil $\mathcal{P}_2$ (MSTB)																				
	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.25	$4.75	$4.75	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.00	$14.00	$20.00	$20.00
100	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.00	$6.75	$9.50	$15.00	$15.75	
200	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.25	$7.25	$11.50	$18.75	$18.75	
300	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.50	$14.25	$14.25		
400	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.75	$6.00	$6.75	$9.75	$17.25	$17.25		
500	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$5.75	$6.50	$8.00	$12.75	$12.75			
600	$5.00	$4.25	$4.25	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.75	$9.[illegible]	$9.[illegible]				
700	$5.25	$4.50	$4.50	$4.25	$4.25	$4.50	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$6.[illegible]	$6.75	$6.[illegible]						
800	[illegible]	$4.[illegible]	$4.[illegible]	$4.75	$4.75	$4.75	$4.75	[illegible]	$5.[illegible]	$5.[illegible]	$5.[illegible]										

Table 9.4: Secondary Economic Limit Abandonment Price $s_{2A}(\mathcal{P}_2,t;\mathcal{P}_1)$ ($/bbl) (continued)

t=20 yrs

Primary Oil $\mathcal{P}_1$ (MSTB)	Secondary Oil $\mathcal{P}_2$ (MSTB)																				
	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.25	$4.75	$4.75	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.00	$14.00	$20.00	
100	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.00	$6.75	$9.50	$15.00	$25.25	$25.50
200	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.25	$7.25	$11.50	$18.75	$18.75	
300	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.50	$14.25	$19.00	$19.[illegible]	
400	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.75	$6.00	$6.75	$9.75	$17.25	$17.25		
500	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$5.75	$6.50	$8.00	$12.75	$12.75			
600	$5.00	$4.25	$4.25	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.75	$9.[illegible]	$9.25				
700	$5.25	$4.50	$4.50	$4.25	$4.25	$4.50	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$6.[illegible]	$6.75	$6.75						
800	$5.50	$4.75	$4.50	$4.75	$4.75	$4.75	$4.75	$5.00	$5.00	$5.25	$5.50	$5.50									

t=21 yrs

Primary Oil $\mathcal{P}_1$ (MSTB)	Secondary Oil $\mathcal{P}_2$ (MSTB)																				
	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.25	$4.75	$4.75	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.00	$14.00	$20.00	
100	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.00	$6.75	$9.50	$15.00	$25.50	
200	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.25	$7.25	$11.50	$18.75	$19.00	
300	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.50	$14.25	$19.00	$19.[illegible]	
400	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.75	$6.00	$6.75	$9.75	$17.25	$17.25		
500	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$5.75	$6.50	$8.00	$12.75	$12.75			
600	$5.00	$4.25	$4.25	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.75	$9.00	$16.[illegible]	$16.[illegible]			
700	$5.25	$4.50	$4.50	$4.25	$4.25	$4.50	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$6.00	$6.75	$9.25	$9.25					
800	$5.50	$4.75	$4.50	$4.75	$4.75	$4.75	$4.75	$5.00	$5.00	$5.25	$5.50	$5.75	$5.75								

t=22 yrs

Primary Oil $\mathcal{P}_1$ (MSTB)	Secondary Oil $\mathcal{P}_2$ (MSTB)																				
	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.25	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.00	$14.00	$20.00	
100	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.00	$6.75	$9.50	$15.00	$25.50	
200	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.25	$7.25	$11.50	$18.75		
300	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.50	$14.25	$19.25	$19.25	
400	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.75	$6.00	$6.75	$9.75	$17.25	$17.25		
500	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$5.75	$6.50	$8.00	$12.75	$18.25	$18.25		
600	$5.00	$4.25	$4.25	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.75	$9.25	$16.00	$16.00			
700	$5.25	$4.50	$4.50	$4.25	$4.25	$4.50	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$6.00	$6.75	$9.25	$9.25					
800	$5.50	$4.75	$4.50	$4.75	$4.75	$4.75	$4.75	$5.00	$5.00	$5.25	$5.50	$5.75	$6.25	$6.25							

t=23 yrs

Primary Oil $\mathcal{P}_1$ (MSTB)	Secondary Oil $\mathcal{P}_2$ (MSTB)																				
	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.25	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.00	$14.00	$20.00	
100	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.00	$6.75	$9.50	$15.00	$25.50	
200	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.25	$7.25	$11.50	$19.00		
300	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.50	$14.25	$19.25		
400	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.75	$6.00	$7.00	$9.75	$17.25	$20.50	$20.50	
500	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$5.75	$6.50	$8.00	$12.75	$18.25	$18.25		
600	$5.00	$4.25	$4.25	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.75	$9.25	$16.00	$16.00			
700	$5.25	$4.50	$4.50	$4.25	$4.25	$4.50	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$6.00	$6.75	$9.25	$12.00	$12.00				
800	$5.50	$4.75	$4.50	$4.75	$4.75	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$5.75	$6.25	$7.50	$7.50						

Table 9.4: Secondary Economic Limit Abandonment Price $s_{2A}(\mathcal{P}_2,t;\mathcal{P}_1)$ (\$/bbl) (continued)

t=24 yrs																					
Primary Oil	Secondary Oil $\mathcal{P}_2$ (MSTB)																				
$\mathcal{P}_1$ (MSTB)	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.25	$4.75	$4.75	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.00	$14.00	$20.00	
100	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.00	$6.75	$9.50	$14.75	$25.25	
200	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.25	$7.25	$11.50	$18.75		
300	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.50	$14.25	$19.00		
400	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.75	$6.00	$6.75	$9.75	$17.00	$20.50		
500	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$5.75	$6.50	$8.00	$12.75	$18.00	[illegible]		
600	$5.00	$4.25	$4.25	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.75	$9.00	$15.75	$16.00			
700	$5.25	$4.50	$4.50	$4.25	$4.25	$4.50	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$6.00	$6.75	$9.25	$12.00	[illegible]				
800	$5.50	$4.75	[illegible]	$4.75	$4.75	$4.75	$4.75	[illegible]	[illegible]	$5.25	$5.50	$5.75	$6.25	$7.50	$12.25	$12.25					

t=25 yrs																					
Primary Oil	Secondary Oil $\mathcal{P}_2$ (MSTB)																				
$\mathcal{P}_1$ (MSTB)	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.25	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.00	$14.00	$20.00	
100	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.00	$6.75	$9.50	$15.00	$25.50	
200	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.25	$7.25	$11.50	$19.00		
300	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.50	$14.25	$19.25		
400	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.75	$6.00	$7.00	$9.75	$17.25	$20.50		
500	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$5.75	$6.50	$8.00	$12.75	$18.25	$18.25		
600	$5.00	$4.25	$4.25	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.75	$9.25	$16.00	[illegible]	[illegible]		
700	$5.25	$4.50	$4.50	$4.25	$4.25	$4.50	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$6.00	$6.75	$9.25	$12.00	[illegible]				
800	[illegible]	$4.75	[illegible]	$4.75	$4.75	$4.75	[illegible]	[illegible]	$5.00	$5.25	$5.50	$5.75	$6.25	$7.50	$12.25	$12.25					

t=26 yrs																					
Primary Oil	Secondary Oil $\mathcal{P}_2$ (MSTB)																				
$\mathcal{P}_1$ (MSTB)	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	[illegible]	$4.25	$4.25	[illegible]	[illegible]	[illegible]	[illegible]	$4.25	$4.25	$4.75	$4.75	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.00	$14.00	$20.00	
100	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.00	$6.75	$9.50	$14.75	$25.25	
200	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.25	$7.25	$11.50	$18.75		
300	$4.75	$4.25	$4.25	[illegible]	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.50	$14.25	$19.00		
400	$4.75	$4.25	$4.25	[illegible]	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.75	$6.00	$6.75	$9.75	$17.00	$20.50		
500	$4.75	$4.25	$4.25	[illegible]	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$5.75	$6.50	$8.00	$12.75	$18.00			
600	$5.00	$4.25	$4.25	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.75	$9.00	$15.75	$20.00	[illegible]		
700	$5.25	$4.50	$4.50	$4.25	$4.25	$4.50	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$6.00	$6.75	$9.25	$12.00	[illegible]	[illegible]			
800	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	$5.75	$6.25	[illegible]	[illegible]	[illegible]					

t=27 yrs																					
Primary Oil	Secondary Oil $\mathcal{P}_2$ (MSTB)																				
$\mathcal{P}_1$ (MSTB)	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	$4.25	$4.25	$4.75	$4.75	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.00	$14.00	$20.00	
100	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.00	$6.75	$9.50	$14.75	$25.25	
200	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.25	$7.25	$11.50	$18.75		
300	[illegible]	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.50	$14.25	$19.00		
400	[illegible]	$4.25	$4.25	[illegible]	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.75	$6.00	$6.75	$9.75	$17.00	$20.50		
500	$4.75	$4.25	$4.25	[illegible]	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$5.75	$6.50	$8.00	$12.75	$18.00			
600	[illegible]	$4.25	$4.25	[illegible]	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.75	$9.00	$15.75	$20.00			
700	$5.25	$4.50	$4.50	$4.25	$4.25	$4.50	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$6.00	$6.75	$9.25	$12.00	$18.50	[illegible]			
800	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	$5.75	$6.25	[illegible]	[illegible]	[illegible]	[illegible]				

Table 9.4: Secondary Economic Limit Abandonment Price $s_{2A}(\mathcal{P}_2,t;\mathcal{P}_1)$ ($/bbl) (continued)

t=28 yrs

Primary Oil	Secondary Oil $\mathcal{P}_2$ (MSTB)																				
$\mathcal{P}_1$ (MSTB)	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.25	$4.75	$4.75	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.00	$14.00	$20.00	
100	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.00	$6.75	$9.50	$14.75	$25.25	
200	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.25	$7.25	$11.50	$18.75		
300	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.50	$14.25	$19.00		
400	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.75	$6.00	$6.75	$9.75	$17.00	$20.50		
500	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$5.75	$6.50	$8.00	$12.75	$18.00			
600	$5.00	$4.25	$4.25	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.75	$9.00	$15.75	$20.00			
700	$5.25	$4.50	$4.50	$4.25	$4.25	$4.50	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$6.00	$6.75	$9.25	$12.00	$18.50	$16.50			
800	$5.50	$4.75	$4.50	$4.75	$4.75	$4.75	$4.75	$5.00	$5.00	$5.25	$5.50	$5.75	$6.25	$7.50	$12.25	$18.75	$18.75				

t=29 yrs

Primary Oil	Secondary Oil $\mathcal{P}_2$ (MSTB)																				
$\mathcal{P}_1$ (MSTB)	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.25	$4.75	$4.75	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.00	$14.00	$20.00	
100	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.00	$6.75	$9.50	$14.75	$25.25	
200	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.25	$7.25	$11.50	$18.75		
300	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.50	$14.25	$19.00		
400	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.75	$6.00	$6.75	$9.75	$17.25	$20.50		
500	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$5.75	$6.50	$8.00	$12.75	$18.00			
600	$5.00	$4.25	$4.25	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.75	$9.00	$15.75	$20.00			
700	$5.25	$4.50	$4.50	$4.25	$4.25	$4.50	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$6.00	$6.75	$9.25	$12.00	$18.50				
800	$5.50	$4.75	$4.50	$4.75	$4.75	$4.75	$4.75	$5.00	$5.00	$5.25	$5.50	$5.75	$6.25	$7.50	$12.25	$18.75	$18.75				

t=30 yrs

Primary Oil	Secondary Oil $\mathcal{P}_2$ (MSTB)																				
$\mathcal{P}_1$ (MSTB)	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.25	$4.75	$4.75	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.00	$14.00	$20.00	
100	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.00	$6.75	$9.50	$14.75	$25.25	
200	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.25	$7.25	$11.50	$18.75		
300	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.50	$14.25	$19.00		
400	$5.00	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.75	$6.00	$6.75	$9.75	$17.25	$20.50		
500	$5.00	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$5.75	$6.50	$8.00	$12.75	$18.00			
600	$5.25	$4.25	$4.25	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.75	$9.00	$15.75	$20.00			
700	$5.50	$4.50	$4.50	$4.25	$4.25	$4.50	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$6.00	$6.75	$9.25	$12.00	$18.50				
800	$5.75	$4.75	$4.50	$4.75	$4.75	$4.75	$4.75	$5.00	$5.00	$5.25	$5.50	$5.75	$6.25	$7.50	$12.25	$18.75	$18.75				

t=31 yrs

Primary Oil	Secondary Oil $\mathcal{P}_2$ (MSTB)																				
$\mathcal{P}_1$ (MSTB)	0	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
0	$4.75	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.25	$4.75	$4.75	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.00	$14.00	$20.00	
100	$5.00	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.00	$6.75	$9.50	$15.00	$25.25	
200	$5.25	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.25	$5.25	$5.50	$5.75	$6.25	$7.25	$11.50	$18.75		
300	$5.25	$4.25	$4.25	$4.00	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.50	$8.50	$14.25	$19.00		
400	$5.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.75	$6.00	$6.75	$9.75	$17.25	$20.50		
500	$5.50	$4.25	$4.25	$4.00	$4.00	$4.00	$4.25	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$5.75	$6.50	$8.00	$12.75	$18.25			
600	$5.75	$4.50	$4.25	$4.00	$4.00	$4.25	$4.50	$4.75	$5.00	$5.00	$5.25	$5.25	$5.50	$6.00	$6.75	$9.00	$16.00	$20.00			
700	$6.00	$4.50	$4.50	$4.25	$4.25	$4.50	$4.75	$5.00	$5.00	$5.00	$5.25	$5.50	$6.00	$6.75	$9.25	$12.00	$18.50				
800	$6.25	$4.75	$4.50	$4.75	$4.75	$4.75	$4.75	$5.00	$5.00	$5.25	$5.50	$5.75	$6.25	$7.50	$12.25	$18.75					

Table 9.4: Secondary Economic Limit Abandonment Price $s_{2A}(\mathcal{P}_2,t;\mathcal{P}_1)$ ($/bbl) (continued)

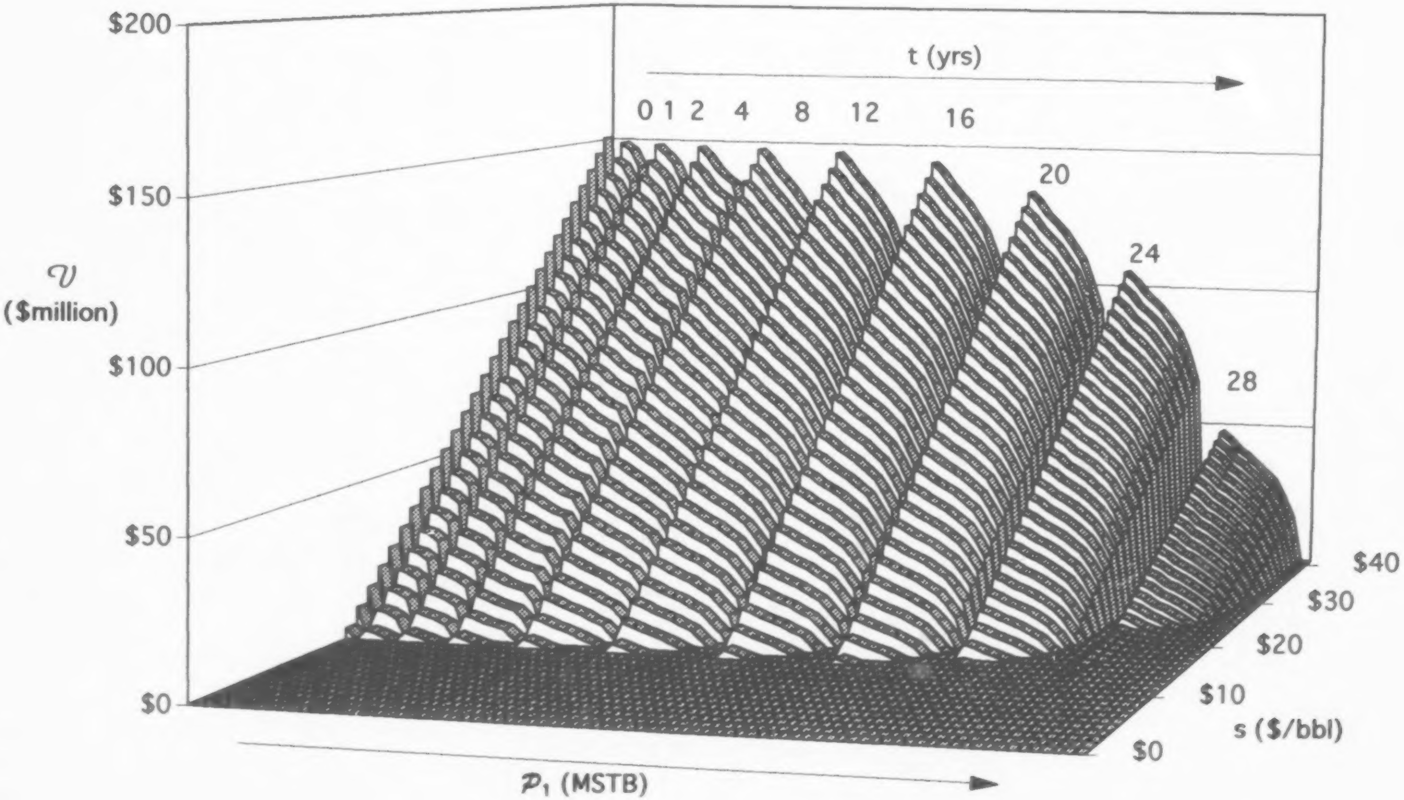


Figure 9.1: Remaining Depletion Strategy Value $\mathcal{V}(s,t,\mathcal{P}_1;\mathcal{D})$

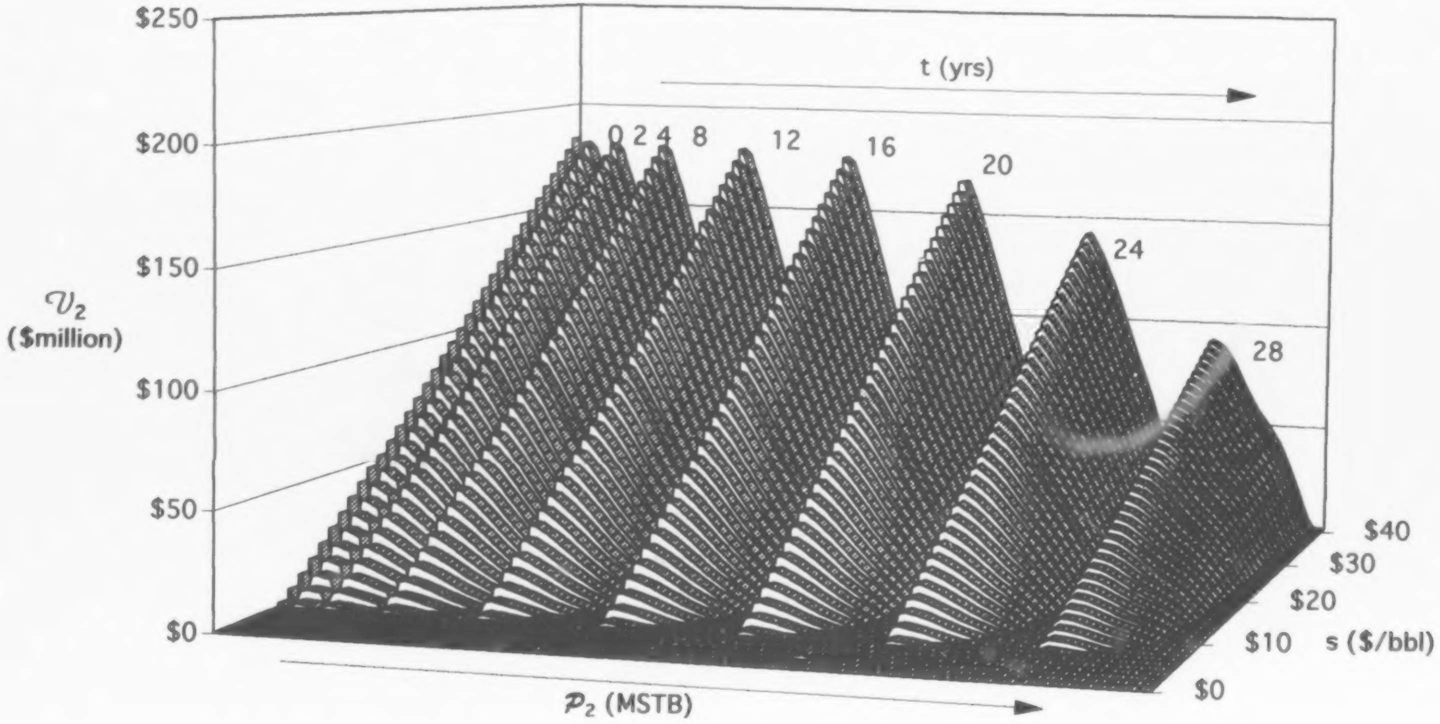


Figure 9.2: Remaining Secondary Value $\mathcal{V}_2(s,t,\mathcal{P}_2;\mathcal{P}_1,\Theta_2)$ for Primary Oil $\mathcal{P}_1$=0 MSTB

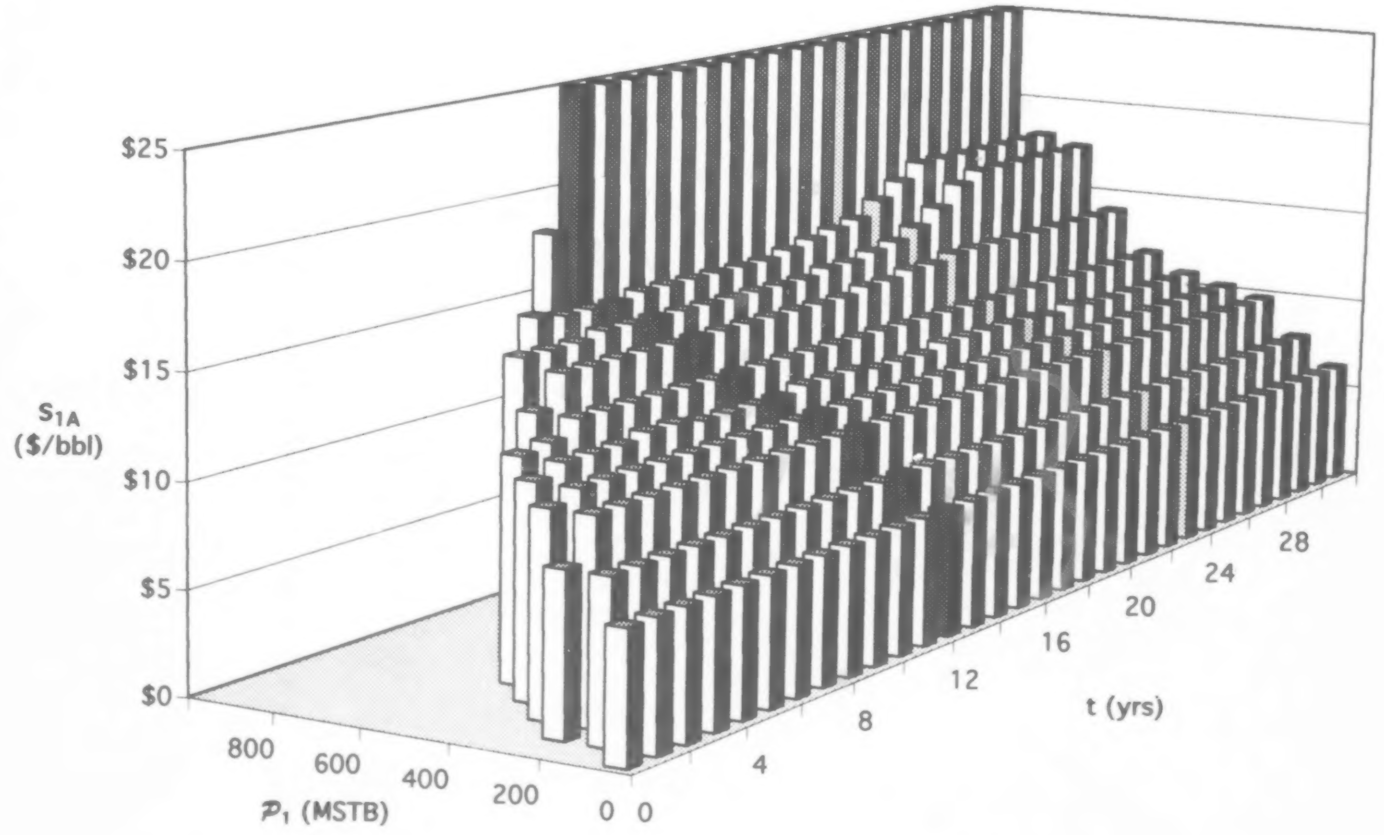


Figure 9.3: Primary Economic Limit Abandonment Price $s_{1A}(t,\mathcal{P}_1)$

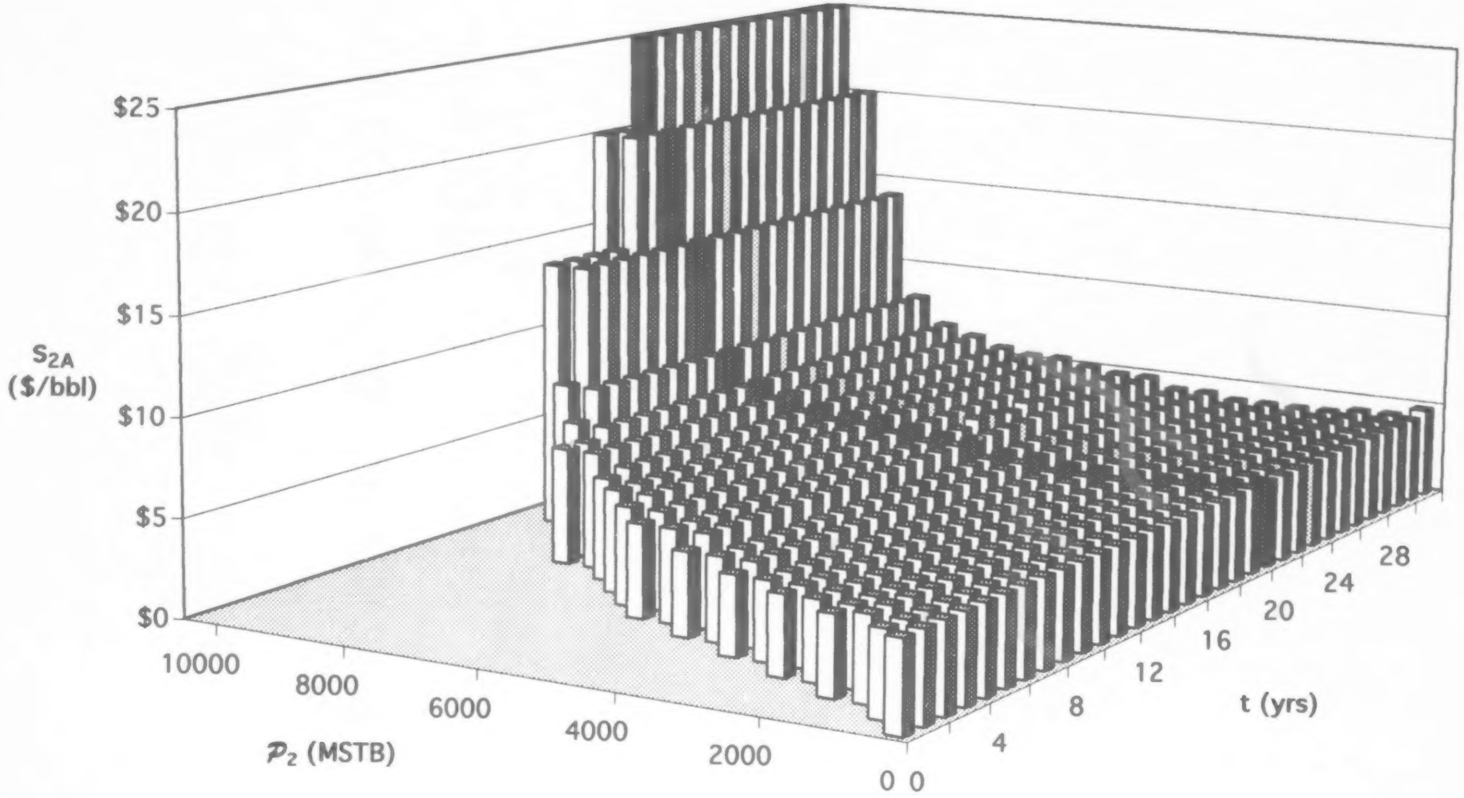


Figure 9.4: Secondary Economic Limit Abandonment Price $s_{2A}(t,\mathcal{P}_2;\mathcal{P}_1)$ for $\mathcal{P}_1=0$

Chapter 10: Conclusion

A methodology has been presented for constructing optional-stage depletion strategies that incorporate a probabilistic economic model for the timing valuation of secondary recovery options. A branched differential decision process using dynamic programming techniques was used to find investment and operating decision rules that maximized the modelled economic value of remaining operating alternatives over a strategic window.

A depletion strategy was constructed for the implementation of an optional waterflood design in the Chedderville Viking "A" pool. The strategy constituted an optimal policy that was compiled as a schedule of price sensitive decision rules to apply at future depletion states, regardless of how model operations are managed up to that point in time. Regulatory constraints limited monthly oil and gas primary production. The model system examined the waterflood investment timing option. The economic limit for early abandonment options were also determined. Modelled economic value depended on the remaining reservoir depletion paths and the probability structure of macro-economic scenarios. The oil price and cumulative oil production were sufficient state variables for decision-making. Oil price expectations assumed an exogenous continuous random walk in volatile future price movements. An intertemporal equilibrium asset valuation model, based on oil futures price dynamics, was used to value production cash flows from alternative recovery paths in terms of macro-economic factors and field-specific costs.

This investigation presents the following contributions to petroleum engineering management:

1) Depletion state variables based on cumulative oil production were approximated and a feasible depletion space for primary and secondary operations defined.

2) The decision model based on probabilistic economic scenarios examined nested primary and secondary operating modes for active control policy, pooled suspension and early abandonment. A dynamic programming algorithm tracked the feasible depletion state boundary constraint for decision times based on cumulative production milestones.

3) A reservoir simulation tool was developed with branched forecasting capabilities for an optional secondary recovery stage at discrete depletion states along the primary life cycle.

4) A well management system for monthly oil and gas regulatory quotas was implemented into the reservoir simulation tool.

5) A primary control policy that adhered to regulatory constraints and a secondary control policy that met waterflood design specifications were proposed.

6) The optional-stage depletion strategy methodology was demonstrated with the realistic application for the Chedderville Viking "A" Pool. The demonstration included:

a) reservoir characterization of Chedderville Viking "A" using geostatistics
b) history matching production and pressure data
c) feasible waterflood project design
d) primary control policy that adheres to regulatory constraints
e) secondary control policy to meet waterflood design objectives
f) branched waterflood production forecasts along the primary life cycle
g) model depletion strategy generated for Chedderville Viking "A"
h) investment timing option analysis and economic limit determination

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Appendix A1: Black Oil Simulation Model

This formulation is based on the "Black Oil Applied Simulation Tool (BOAST)" developed by Franchi *et al.* (1982).

A1.1 Reservoir Volume Elements

A principle axis transformation aligns the areal coordinate system with core permeability trends. The longitudinal maximum and transverse 90° permeability directions corresponds to the rectilinear x- and y-axis, respectively. The vertical z-axis is in the direction of increasing depth. Rectilinear coordinate unit vectors ($\mathbf{e}_x$, $\mathbf{e}_y$, $\mathbf{e}_z$) define (x, y, z) directions. Vector $\mathbf{x}=(x, y, z)$ defines the location of a volume element ($\Delta\mathbf{x}$) within the porous reservoir domain.

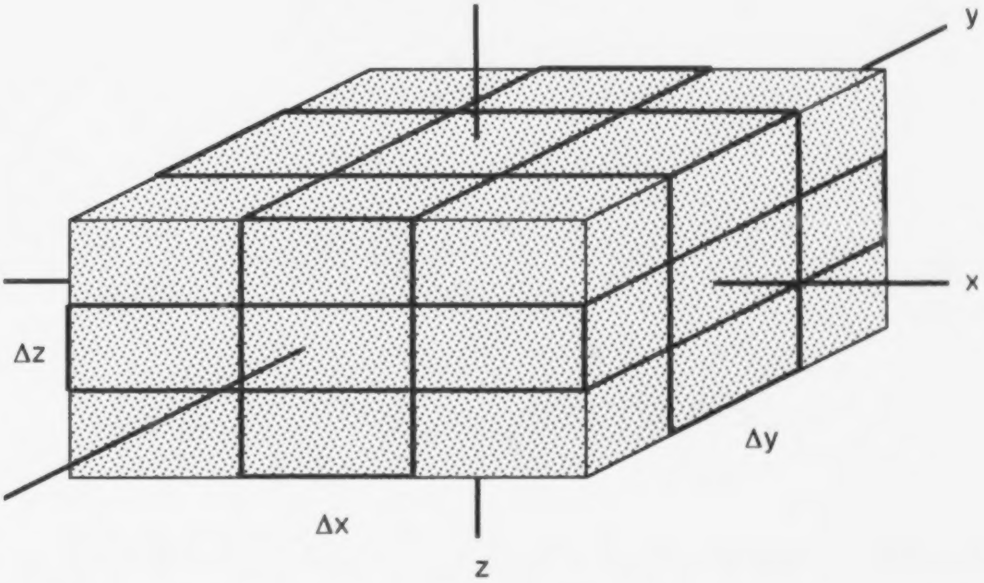

Figure A1.1: Reservoir Grid Coordinate System

The rock matrix is partitioned on a block-centered grid into (N_x, N_y, N_z) intervals of dimension (Δx, Δy ,Δz). Areal grid block boundaries map directly onto a discrete coordinate mesh on the x-y plane.

$$\begin{aligned} x_i &= x_{i-1} + \Delta x_i \qquad i=1,2,\ldots,N_x \\ y_j &= y_{j-1} + \Delta y_j \qquad j=1,2,\ldots,N_y \end{aligned} \tag{A1.1}$$

The formation top depth $z_0(x,y)$ is measured from the reference areal coordinate system at sea level (z=0). The thickness partition is generally a function of the specific volume element $\Delta z(x,y,z)$. The depth of a specific volume element is determined recursively from the location of the volume element above.

$$z_k(x,y) = z_{k-1}(x,y) + \Delta z_k(x,y) \qquad k = 1,2,\ldots,N_z \tag{A1.2}$$

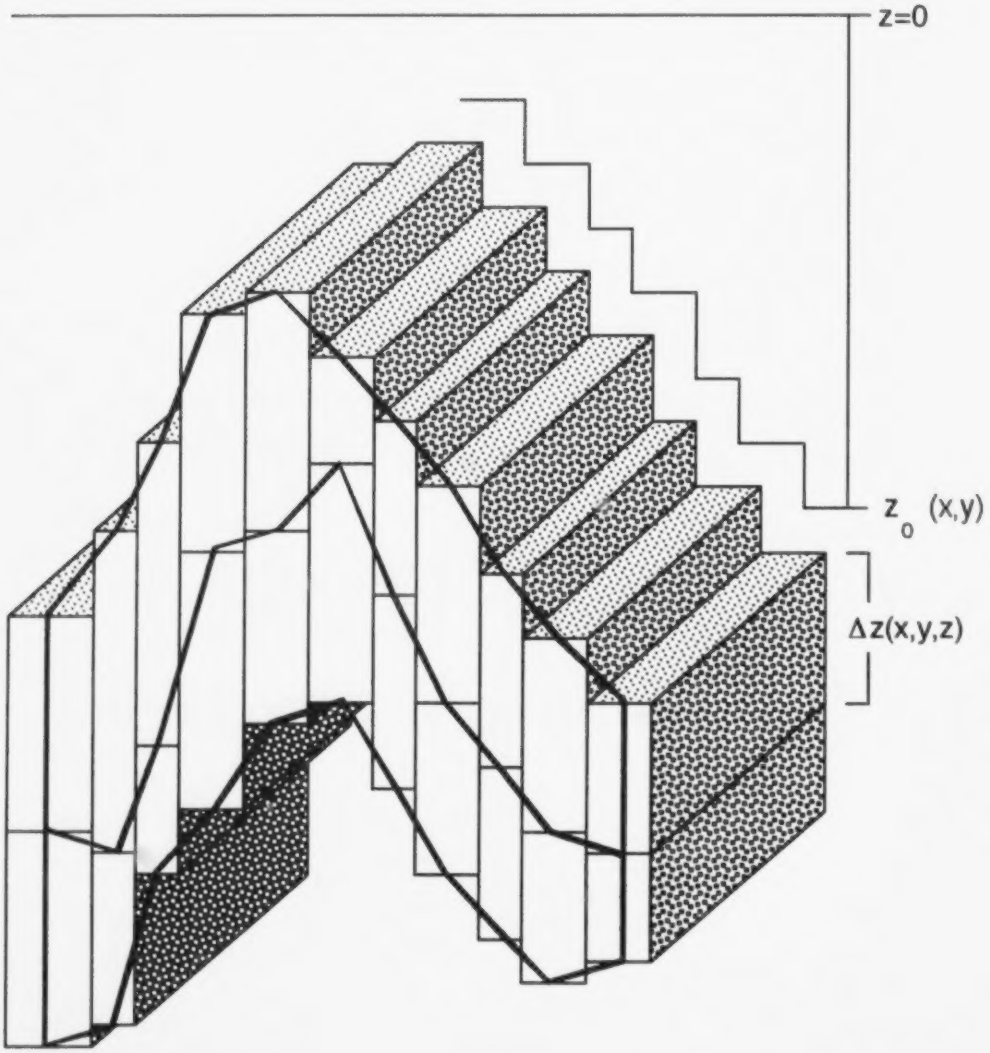

Figure A1.2: Irregular Thickness Partition with Skewed Elements

The irregular grid partition in the z-direction may result in skewed volume elements. Skewness occurs when connected faces of adjacent elements are located at different depths. Elemental bulk volumes ($\Delta V_b = \Delta \mathbf{x}$) are defined in terms of discrete elemental dimensions (Δx_i, Δy_j, Δz_{ijk}).

$$\Delta V_b = \Delta x_i \, \Delta y_j \, \Delta z_{ijk} \qquad \text{(A1.3)}$$

A1.2 Volume Fractions

Reservoir porosity (ϕ) is defined as the locally-averaged void volume-fraction of the rock matrix. Rock compressibility (c_r) is assumed to be a function of the reservoir pressure (p).

$$\frac{\partial \phi}{\partial p} = c_r(p) \qquad \text{(A1.4)}$$

Phase saturations (S_o, S_w, S_g) are defined as locally-averaged rock void volume-fractions occupied by the respective phases of oil water and gas.

$$S_o + S_w + S_g = 1 \qquad \text{(A1.5)}$$

A1.3 Capillary Pressures

Each phase can occupy a distinct portion of the pore space, with the formation of oil-water and gas-oil interfacial boundaries. The surface tension at these boundaries create a capillary pressure difference between the distinct phase pressures (p_o, p_w, p_g). The reservoir fluid pressure (p) is typically in terms of the oil pressure (p_o=p). Oil-water and gas-oil capillary pressures (p_{cow}, p_{cgo}) are functions of water and gas saturations, respectively.

$$\begin{aligned} p_{cow}(S_w) &= p_o - p_w \\ p_{cgo}(S_g) &= p_g - p_o \end{aligned} \qquad \text{(A1.6)}$$

A1.4 Fluid Volumes

Reservoir fluid volumes (V_o, V_w, V_g) are converted into a standard fluid volumes (V_{sco}, V_{scw}, V_{scg}) by formation volume factors (B_o, B_w, B_g). Formation volume factors have units of reservoir fluid volume per unit standard fluid volume. Isothermal reservoir volumes depend on reservoir pressure (p). The Standard volume is one barrel at stock tank conditions (1 atm, 60° F) for oil and formation water. The gas standard volume is one standard cubic foot (1 atm, 60° F).

$$B_o = \frac{V_o(p)}{V_{sco}} \qquad B_w = \frac{V_w(p)}{V_{scw}} \qquad B_g = \frac{V_g(p)}{V_{scg}} \tag{A1.7}$$

Gas can either flow in its free form, or flow as a dissolved component with oil and water. The reservoir liquid volumes (V_o, V_w) will include dissolved gas. The volume of dissolved gas depends on its solubility. Gas solubilities (R_{so}, R_{sw}) are expressed in standard volumes of gas dissolved in standard volumes of liquid. Isothermal gas solubilities are functions of pressure.

$$R_{so} = R_{so}(p) \qquad R_{sw} = R_{sw}(p) \tag{A1.8}$$

A1.5 Conservation of Mass

The phase velocity ($\mathbf{v}_o$, $\mathbf{v}_w$, $\mathbf{v}_g$) is defined as the reservoir volumetric flux. Standard densities (ρ_{sco}, ρ_{scw}, ρ_{scg}) relate standard volumes to mass. Mass is conserved for each phase. The rate of mass accumulation in a volume element must equal the combined rates of net mass influx from adjacent elements and mass source introduced from within. Mass concentration sources (q_o, q_w, q_g) are defined in terms of fluid mass rates per unit reservoir volume. Conservation of mass equations are determined using Gauss's divergence theorem over individual volume elements. The system of partial differential equations in differential vector form are:

$$-\nabla \cdot \frac{\mathbf{v}_o}{B_o} - \frac{q_o}{\rho_{sco}} = \frac{\partial}{\partial t}(\phi \frac{S_o}{B_o})$$

$$-\nabla \cdot \frac{\mathbf{v}_w}{B_w} - \frac{q_w}{\rho_{scw}} = \frac{\partial}{\partial t}(\phi \frac{S_w}{B_w})$$

$$-\nabla \cdot (\frac{\mathbf{v}_g}{B_g} + \frac{R_{so}\mathbf{v}_o}{B_o} + \frac{R_{sw}\mathbf{v}_w}{B_w}) - \frac{q_g}{\rho_{scg}} = \frac{\partial}{\partial t}[\phi(\frac{S_g}{B_g} + \frac{R_{so}S_o}{B_o} + \frac{R_{sw}S_w}{B_w})]$$

(A1.9)

Wells provide fluid sources and sinks into reservoir volume elements at specific locations $\{\mathbf{x}_{ijk}\}$. Production wells are negative sinks and injection wells are positive sources. Well flows are in terms of a standard volumetric flow rates (Q_o, Q_w, Q_g). The appropriate mass concentration source terms (q_o, q_w, q_g) distribute point flows over the physical volume of the reservoir element ($\Delta\mathbf{x}$).

$$Q_o = \frac{q_o(\mathbf{x})}{\rho_{sco}}\Delta\mathbf{x}$$

$$Q_w = \frac{q_w(\mathbf{x})}{\rho_{scw}}\Delta\mathbf{x}$$

$$Q_g = \frac{q_g(\mathbf{x})}{\rho_{scg}}\Delta\mathbf{x} \qquad \text{(A1.10)}$$

A1.6 Phase Potentials

Phase potentials (Φ_o, Φ_w, Φ_g) are defined as sum of hydrodynamic pressures and hydrostatic heads at depth (z).

$$\Phi_o = p_o + \rho_o gz$$

$$\Phi_w = p_w + \rho_w gz$$

$$\Phi_g = p_g + \rho_g gz \qquad \text{(A1.11)}$$

A1.7 Darcy Velocities

Darcy's equation relates the fluid flux to the potential gradient. The resistance to flow is determined by the rock permeability ($\tilde{K}$), a dyadic tensor of rank two.

$$\mathbf{v}_o = -\tilde{K} \cdot \lambda_o \nabla \Phi_o$$

$$\mathbf{v}_w = -\tilde{K} \cdot \lambda_w \nabla \Phi_w$$

$$\mathbf{v}_g = -\tilde{K} \cdot \lambda_g \nabla \Phi_g \qquad \text{(A1.12)}$$

The rock permeability ($\tilde{K}$) tensor accounts for the anisotropic nature of the reservoir pore structure, where a potential gradient can produce component flows in different directions. A principle axis transformation diagonalizes the tensor matrix into longitudinal, transverse and vertical permeability components (K_x, K_y, K_z) to align with directions of the coordinate unit vectors ($\mathbf{e}_x$, $\mathbf{e}_y$, $\mathbf{e}_z$).

$$\begin{aligned}
\mathbf{v}_o &= -\lambda_o\left[K_x\frac{\partial}{\partial x}\mathbf{e}_x + K_y\frac{\partial}{\partial y}\mathbf{e}_y + K_z\frac{\partial}{\partial z}\mathbf{e}_z\right]\Phi_o \\
\mathbf{v}_w &= -\lambda_w\left[K_x\frac{\partial}{\partial x}\mathbf{e}_x + K_y\frac{\partial}{\partial y}\mathbf{e}_y + K_z\frac{\partial}{\partial z}\mathbf{e}_z\right]\Phi_w \qquad \text{(A1.13)} \\
\mathbf{v}_g &= -\lambda_g\left[K_x\frac{\partial}{\partial x}\mathbf{e}_x + K_y\frac{\partial}{\partial y}\mathbf{e}_y + K_z\frac{\partial}{\partial z}\mathbf{e}_z\right]\Phi_g
\end{aligned}$$

The phase mobilities (λ_o, λ_w, λ_g) are the ratios of the phase relative permeabilities (k_{ro}, k_{rw}, k_{rg}) to phase viscosities (μ_o, μ_w, μ_g). Isothermal phase viscosities depend on pressure (p). Oil and water viscosities account for the effects of dissolved gas in solution. Three-phase relative permeabilities are assumed to have a functional dependence on (S_o, S_w, S_g) as proposed in the probability models of Stone (1970, 1973).

$$\lambda_o = \frac{k_{ro}(S_w, S_g)}{\mu_o(p)} \qquad \lambda_w = \frac{k_{rw}(S_w)}{\mu_w(p)} \qquad \lambda_g = \frac{k_{rg}(S_g)}{\mu_g(p)} \qquad \text{(A1.14)}$$

A1.8 Oil Pressure Equation

The oil pressure equation is derived by eliminating phase saturations using the identity (A1.5), the Darcy-continuity equations (A1.9-A1.13) and the capillary pressures (A1.6). Isothermal formation volume factors (A1.7), gas solubilities (A1.8) and porosity (A1.4) are functions of pressure only. Time derivatives in (A1.9) can be expanded using the chain rule. Phase compressibility coefficients (c_o, c_w, c_g) are defined in terms of reservoir phase volumes.

$$\begin{aligned}
c_o &= -\frac{1}{B_o}\frac{\partial B_o}{\partial p} + \frac{B_g}{B_o}\frac{\partial R_{so}}{\partial p} \\
c_w &= -\frac{1}{B_w}\frac{\partial B_w}{\partial p} + \frac{B_g}{B_w}\frac{\partial R_{sw}}{\partial p} \qquad \text{(A1.15)} \\
c_g &= -\frac{1}{B_g}\frac{\partial B_g}{\partial p}
\end{aligned}$$

The total compressibility coefficient (c_t) is the sum of component coefficients:

$$c_t = c_r + c_o S_o + c_w S_w + c_g S_g \qquad \text{(A1.16)}$$

The oil pressure equation in differential form becomes:

$$\begin{aligned}
\phi c_t \frac{\partial p}{\partial t} = {} & (B_o - R_{so} B_g)[\nabla \cdot \tilde{K} \cdot \frac{\lambda_o}{B_o} \nabla (p - \rho_o g z) - \frac{q_o}{\rho_{sco}}] \\
& + (B_w - R_{sw} B_g)[\nabla \cdot \tilde{K} \cdot [\frac{\lambda_w}{B_w} \nabla (p - \rho_w g z) - \frac{\lambda_w}{B_w} \nabla p_{cow}] - \frac{q_w}{\rho_{scw}}] \\
& + B_g [\nabla \cdot \tilde{K} \cdot [(\frac{\lambda_g}{B_g} + \frac{R_{so} \lambda_o}{B_o} + \frac{R_{sw} \lambda_w}{B_w}) \nabla p - \frac{R_{so} \lambda_o}{B_o} \nabla (\rho_o g z) \\
& + \frac{\lambda_g}{B_g} \nabla (p_{cgo} - \rho_g g z) - \frac{R_{sw} \lambda_w}{B_w} \nabla (p_{cow} + \rho_w g z)] - \frac{q_g}{\rho_{scg}}]
\end{aligned} \qquad \text{(A1.17)}$$

The pressure equation has no explicit time derivatives of saturation.

A1.9 Saturation Equations

Oil and water saturations are determined directly from the Darcy-continuity equations (A1.9)-(A1.13) :

$$\begin{aligned}
\frac{\partial}{\partial t}(\phi \frac{S_o}{B_o}) &= \nabla \cdot \tilde{K} \cdot \frac{\lambda_o}{B_o} \nabla (p - \rho_o g z) - \frac{q_o}{\rho_{sco}} \\
\frac{\partial}{\partial t}(\phi \frac{S_w}{B_w}) &= \nabla \cdot \tilde{K} \cdot \frac{\lambda_w}{B_w} \nabla (p - \rho_w g z) - \nabla \cdot \tilde{K} \cdot \frac{\lambda_w}{B_w} \nabla p_{cow} - \frac{q_w}{\rho_{scw}}
\end{aligned} \qquad \text{(A1.18)}$$

and the gas saturation from the identity (A1.5).

$$S_g = 1 - S_o - S_w \qquad \text{(A1.19)}$$

A1.10 Finite Difference Equations

The system of partial differential equations (A1.17)-(A1.19) at time t^n are spatially integrated over grid block volume elements $\Delta \mathbf{x}_{ijk}$ and temporally integrated over a time step Δt. Block boundary transmissibilities (T_x, T_y, T_z) are defined between grid block (i,j,k) and corresponding adjacent blocks (i-1,j,k), (i,j-1,k) and (i,j,k-1) as:

$$T_{x_{i-\frac{1}{2},j,k}} = \frac{2(K_{x_{i,j,k}} \Delta y_{i,j,k} \Delta z_{i,j,k})(K_{x_{i-1,j,k}} \Delta y_{i-1,j,k} \Delta z_{i-1,j,k})}{K_{x_{i,j,k}} \Delta x_{i-1,j,k} + K_{x_{i-1,j,k}} \Delta x_{i,j,k}}$$

$$T_{y_{i,j-\frac{1}{2},k}} = \frac{2(K_{y_{i,j,k}} \Delta x_{i,j,k} \Delta z_{i,j,k})(K_{y_{i,j-1,k}} \Delta x_{i,j-1,k} \Delta z_{i,j-1,k})}{K_{y_{i,j,k}} \Delta y_{i,j-1,k} + K_{y_{i,j-1,k}} \Delta y_{i,j,k}}$$

$$T_{z_{i,j,k-\frac{1}{2}}} = \frac{2(K_{z_{i,j,k}} \Delta x_{i,j,k} \Delta y_{i,j,k})(K_{z_{i,j,k-1}} \Delta x_{i,j,k-1} \Delta y_{i,j,k-1})}{K_{z_{i,j,k}} \Delta z_{i,j,k-1} + K_{z_{i,j,k-1}} \Delta z_{i,j,k}} \qquad \text{(A1.20)}$$

The Darcy phase transmissibilities (A_o, A_w, A_g) at the block boundaries are calculated using upstream-weighted relative permeability and arithmetic mean values for viscosity and formation volume factor.

$$A_{o_{x\,i-\frac{1}{2},j,k}} = \frac{k_{ro}}{\mu_o B_o} T_{x_{i-\frac{1}{2},j,k}} \quad A_{w_{x\,i-\frac{1}{2},j,k}} = \frac{k_{rw}}{\mu_w B_w} T_{x_{i-\frac{1}{2},j,k}} \quad A_{g_{x\,i-\frac{1}{2},j,k}} = \frac{k_{rg}}{\mu_g B_g} T_{x_{i-\frac{1}{2},j,k}}$$

$$A_{o_{y\,i,j-\frac{1}{2},k}} = \frac{k_{ro}}{\mu_o B_o} T_{y_{i,j-\frac{1}{2},k}} \quad A_{w_{y\,i,j-\frac{1}{2},k}} = \frac{k_{rw}}{\mu_w B_w} T_{y_{i,j-\frac{1}{2},k}} \quad A_{g_{y\,i,j-\frac{1}{2},k}} = \frac{k_{rg}}{\mu_g B_g} T_{y_{i,j-\frac{1}{2},k}}$$

$$A_{o_{z\,i,j,k-\frac{1}{2}}} = \frac{k_{ro}}{\mu_o B_o} T_{z_{i,j,k-\frac{1}{2}}} \quad A_{w_{z\,i,j,k-\frac{1}{2}}} = \frac{k_{rw}}{\mu_w B_w} T_{z_{i,j,k-\frac{1}{2}}} \quad A_{g_{z\,i,j,k-\frac{1}{2}}} = \frac{k_{rg}}{\mu_g B_g} T_{z_{i,j,k-\frac{1}{2}}}$$

(A1.21)

Central-difference operators ($\Delta_x, \Delta_y, \Delta_z$) are used to approximate the differential vector operator (∇). Gauss's divergence theorem applied over the volume element $\Delta\mathbf{x}_{ijk}$ gives:

$$\iiint_{\Delta\mathbf{x}_{ijk}} (\nabla\cdot\tilde{K}\cdot\frac{\lambda_o}{B_o}\nabla p)\,d\mathbf{x} = \Delta A_o \Delta p = \Delta_x A_{o_x} \Delta_x p + \Delta_y A_{o_y} \Delta_y p + \Delta_z A_{o_z} \Delta_z p$$

$$\iiint_{\Delta\mathbf{x}_{ijk}} (\nabla\cdot\tilde{K}\cdot\frac{\lambda_w}{B_w}\nabla p)\,d\mathbf{x} = \Delta A_w \Delta p = \Delta_x A_{w_x} \Delta_x p + \Delta_y A_{w_y} \Delta_y p + \Delta_z A_{w_z} \Delta_z p$$

$$\iiint_{\Delta\mathbf{x}_{ijk}} (\nabla\cdot\tilde{K}\cdot\frac{\lambda_g}{B_g}\nabla p)\,d\mathbf{x} = \Delta A_g \Delta p = \Delta_x A_{g_x} \Delta_x p + \Delta_y A_{g_y} \Delta_y p + \Delta_z A_{g_z} \Delta_z p$$

(A1.22)

where

$$\Delta_x A_{o_x} \Delta_x p = A_{o_{x\,i+\frac{1}{2},j,k}}(p_{i+1,j,k} - p_{i,j,k}) - A_{o_{x\,i-\frac{1}{2},j,k}}(p_{i,j,k} - p_{i-1,j,k})$$

$$\Delta_x A_{o_y} \Delta_x p = A_{o_{y\,i,j+\frac{1}{2},k}}(p_{i,j+1,k} - p_{i,j,k}) - A_{o_{y\,i,j-\frac{1}{2},k}}(p_{i,j,k} - p_{i,j-1,k})$$

$$\Delta_x A_{o_z} \Delta_x p = A_{o_{z\,i,j,k+\frac{1}{2}}}(p_{i,j,k+1} - p_{i,j,k}) - A_{o_{z\,i,j,k-\frac{1}{2}}}(p_{i,j,k} - p_{i,j,k-1})$$

(A1.23)

Using this notation with explicit sources and sinks, the oil equation becomes:

$$\left[\Delta\, A_o^n \Delta(p^{n+1} - \rho_o^n gz) - Q_o^n\right]_{i,j,k} = \frac{1}{\Delta t}\left[(\frac{\phi S_o}{B_o})^{n+1} - (\frac{\phi S_o}{B_o})^{n}\right]_{i,j,k} \Delta V_{b_{i,j,k}} \qquad \text{(A1.24)}$$

the water equation becomes:

$$\left[\Delta\, A_w^n \Delta(p^{n+1} - \rho_w^n gz - p_{cow}^n) - Q_w^n\right]_{i,j,k} = \frac{1}{\Delta t}\left[(\frac{\phi S_w}{B_w})^{n+1} - (\frac{\phi S_w}{B_w})^{n}\right]_{i,j,k} \Delta V_{b_{i,j,k}}$$

(A1.25)

and the pressure equation becomes:

$$\begin{aligned}\frac{1}{\Delta t}\left[\phi^{n} c_t^n (p^{n+1} - p^n)\right]_{i,j,k} \Delta V_{b_{i,j,k}} &= (B_o^n - B_g^n R_{so}^n)_{i,j,k}\left[\Delta A_o^n \Delta(p^{n+1} - \rho_o^n g z) - Q_o^n\right]_{i,j,k} \\ &+ (B_w^n - B_g^n R_{sw}^n)_{i,j,k}\left[\Delta A_w^n \Delta(p^{n+1} - \rho_w^n g z - p_{cow}^n) - Q_w^n\right]_{i,j,k} \\ &+ (B_g^n)_{i,j,k}\left[\begin{array}{c}\Delta A_g^n \Delta(p^{n+1} - \rho_g^n g z + p_{cgo}^n) + \Delta R_{so}^n A_o^n \Delta(p^{n+1} - \rho_o^n g z) \\ + \Delta R_{sw}^n A_w^n \Delta(p^{n+1} - \rho_w^n g z - p_{cow}^n) - Q_g^n\end{array}\right]_{i,j,k}\end{aligned} \tag{A1.26}$$

The pressure equation can be rearranged to a standard difference form:

$$\begin{aligned}Z_{i,j,k} p_{i,j,k-1}^{n+1} + B_{i,j,k} p_{i,j-1,k}^{n+1} + D_{i,j,k} p_{i-1,j,k}^{n+1} + E_{i,j,k} p_{i,j,k}^{n+1} \\ + F_{i,j,k} p_{i+1,j,k}^{n+1} + H_{i,j,k} p_{i,j+1,k}^{n+1} + S_{i,j,k} p_{i,j,k+1}^{n+1} = Q_{i,j,k}^n\end{aligned} \tag{A1.27}$$

The hepta-diagonal system is solved algebraicly using a direct method with symbolic D4-ordering (Oguztoreli 1984, Oguztoreli 1988).

A1.11 Numerical Stability

The finite difference equations are implicitly solved for the pressure distribution at forward times (t^{n+1}) using known phase saturations at time (t^n). Phase saturations are then explicitly determined using forward pressure distributions. Equations implicit in pressure will be stable for any time step size. However, oscillatory and divergent behaviour of explicit saturations will limit the step size. Franchi *et al.* (1982) do not discuss numerical stability. Mattax and Dalton (1990) briefly address this topic and grid orientation effects.

The step size must ensure that no more than one grid block pore volume throughput can occur over any timestep. Stability criteria for flux conservative equations are generally Courant conditions (Courant-Friedrichs-Lewy stability criterion):

$$\frac{|\mathbf{u}|\Delta t}{\Delta \xi} \le N_{\text{Courant}} \tag{A1.28}$$

where $\Delta\xi$ is a characteristic length and **u** is the velocity. The Courant number is typically less than one. A courant condition can be established for each phase, of which the minimum time step is chosen. Oil and water saturation equations can be expressed in the form:

$$\frac{\partial S^*}{\partial t} = -\nabla \cdot (\mathbf{u}S^*) \tag{A1.29}$$

where S^* is the phase volumetric bulk concentration and **u** is its propagation velocity. A gas saturation equation can also be defined in the same form. The Courant number in three dimensions is $N_{Courant}=3^{-0.5}=0.58$ (Press *et al.* 1986). Propagation velocities can be approximated by explicit Darcy phase velocities divided by phase volumetric bulk concentrations. Source terms can be treated in the same manner. A problem with inherent instability was used as a test case. Stability was obtained for $N_{Courant}=0.25$.

Other factors may also affect the stability in simulation. Numerical solution will always has some degree of local oscillation, and will be heightened by the presence of free gas. The sum total of phase saturations is fixed so that free gas can be calculated directly from oil and water saturations. An overshoot in combined oil and water saturations will typically clip and redistribute the error. This clip may create a local transient error that could propagate with time or die out if time steps are small. A danger exists when undershoot in combined oil and water saturations persist to form numerical free gas. Numerical free gas coupled with bubble point tracking can lead to spurious numerical free gas production above the bubble point. A minuscule amount of numerical free gas in an undersaturated grid block can shift the true bubble point to a level above the contemporaneous reservoir pressure. This can be problematic when waterflood has repressurized the reservoir above the bubble point and a free gas zone grows from numerical bubble point hysteresis. Checks must be in place to zero free gas saturation above the bubble point and redistribute the undershoot between oil and water. Bubble point tracking should not be active above the bubble point. This is not a typical problem and may not happen in most cases. Care must be taken whenever new techniques are applied to existing methods.

Appendix A2: Dynamic Programming Algorithm

The numerical algorithm is based on finite-difference dynamic programming methods with critical boundary tracking procedures.

A2.1 Depletion-Time Grid Partition

Time is partitioned into discrete decision time steps Δt^n. Decision times (t^n) are chosen not to exceed quarterly intervals ($\Delta t^n \leq 91.3125$ days) over 32 years of strategic planning.

$$t^n = t^{n+1} - \Delta t^n \tag{A2.1}$$

Discrete primary depletion states ($\mathcal{P}_1^{m_1}$) are calculated over ($M_1=9$) primary cumulative oil production steps ($\Delta\mathcal{P}_1=100$ MSTB). Figure A2.1 shows the primary depletion state-time grid partition.

$$\mathcal{P}_1^{m_1} = m_1 \Delta \mathcal{P}_1 \qquad m_1=0,1,\ldots,M_1 \tag{A2.2}$$

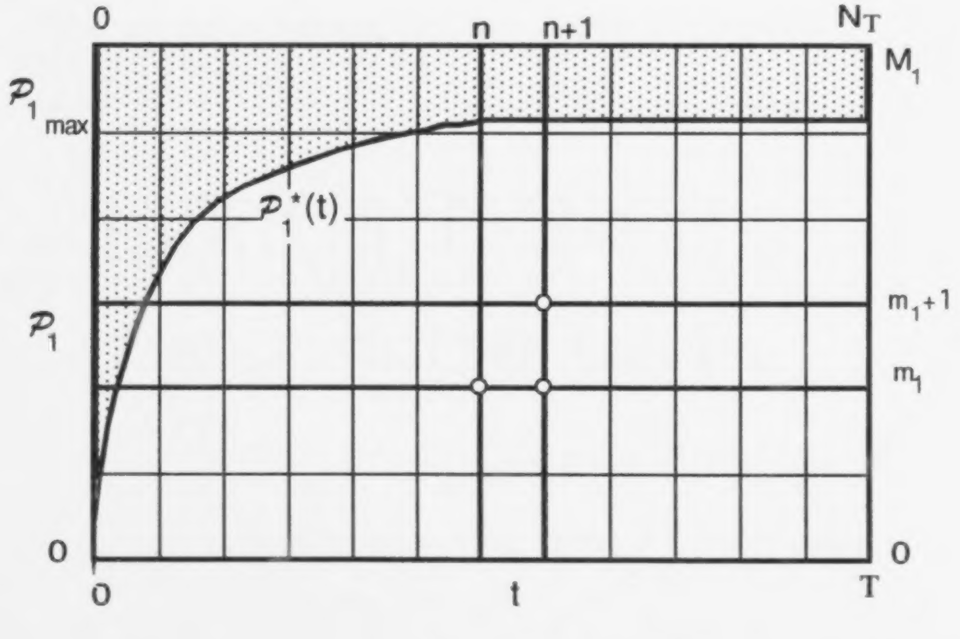

Figure A2.1: Primary Depletion-Time ($\mathcal{P}_1$,t) Grid with Temporal Boundary

The stationary grid partition tracks a time-dependent feasible primary depletion boundary. The maximum grid primary depletion state ($\mathcal{P}_1^{M1}$=900 MSTB) covers the feasible cumulative oil production range under sustained primary control $\mathcal{P}_1^*(T)$=843 MSTB.

Discrete secondary depletion states ($\mathcal{P}_2^{m2}$) are calculated over (M_2=20) secondary cumulative oil production steps ($\Delta\mathcal{P}_2$=500 MSTB). Figure A2.2 shows the secondary depletion state-time grid partition.

$$\mathcal{P}_2^{m_2} = m_2 \Delta\mathcal{P}_2 \qquad m_2=0,1,\ldots,M_2 \qquad \text{(A2.3)}$$

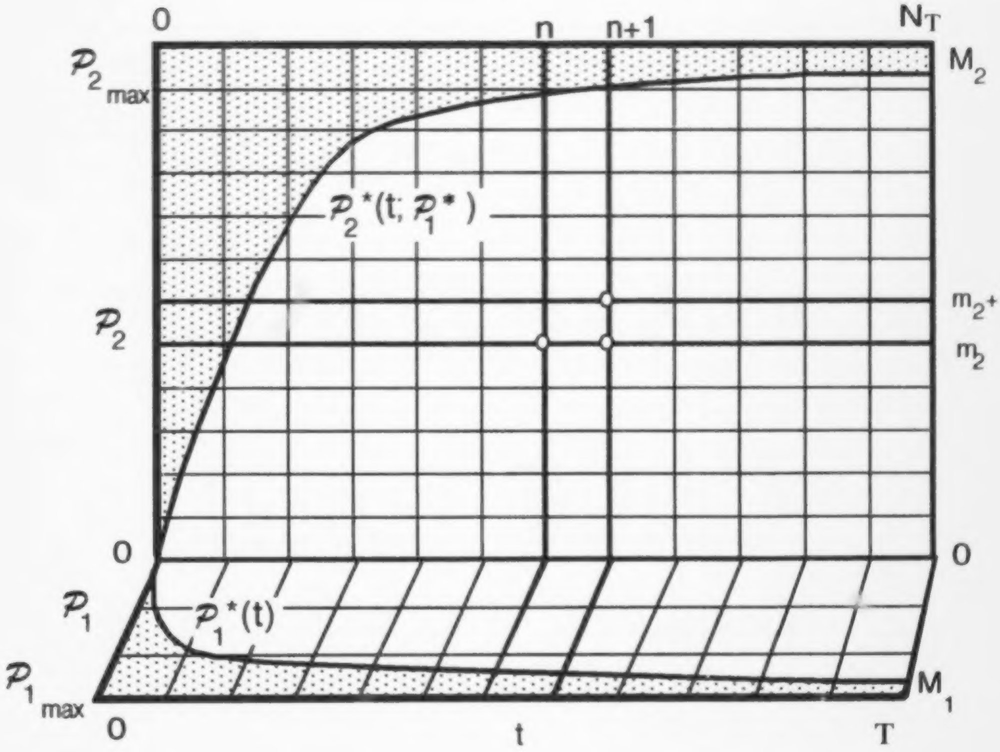
0
n
n+1
N_T
$\mathcal{P}_{2_{max}}$
M_2
$\mathcal{P}_2^*(t; \mathcal{P}_1^*)$
m_2+1
$\mathcal{P}_2$
m_2
0
0
$\mathcal{P}_1$
$\mathcal{P}_1^*(t)$
$\mathcal{P}_{1_{max}}$
M_1
0
t
T

Figure A2.2: Secondary Depletion-Time ($\mathcal{P}_2$,t) Grid with Temporal Boundary

The stationary grid partition tracks a time-dependent secondary depletion boundary. The maximum grid secondary depletion state ($\mathcal{P}_2^{M2}$=10,000 MSTB) covers the feasible cumulative oil production range under sustained secondary control, $\mathcal{P}_2^*(T;\mathcal{P}_1=0) = 9745$ MSTB. The $(\mathcal{P}_1,\mathcal{P}_2,t)$ grid partition encapsulates the space of all feasible depletion paths.

Section 7.5 discusses production rate time-averaging over cumulative oil production milestones. Table 7.1(a) tabulates cumulative time (t_o) for cumulative oil production to reach the milestone partition under the active control. The $(M_1 \times M_2)$ path-dependent table of cumulative production times $t_o(m_1,m_2)$ maps the feasible depletion region in $(\mathcal{P}_1,\mathcal{P}_2,t)$ space as shown in Figure A2.3. The table is directional along the primary branch $(m_1,0)$ and along secondary branches (m_1,m_2). Branch endpoints $(M_1,M_2^{m_1})$ track partial cumulative production intervals $(\Delta\mathcal{P}_1,\Delta\mathcal{P}_2)$ that map off mesh centers (m_1,m_2).

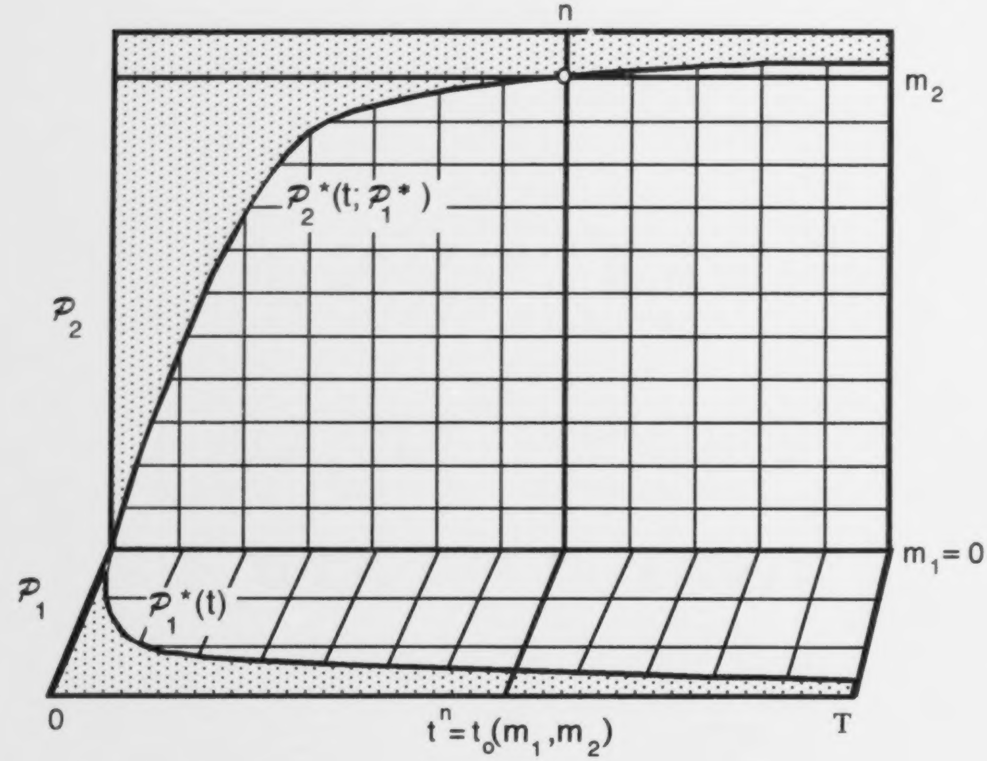

Figure A2.3: Feasible Depletion State Cumulative Time Mapping

$$\mathcal{P}_1^*(t_o(m_1,0)) = \mathcal{P}_1^{m_1} \qquad m_1 = 0,1,\ldots,M_1 - 1$$

$$\mathcal{P}_2^*(t_o(m_1,m_2)) = \mathcal{P}_2^{m_2} \qquad m_2 = 0,1,\ldots,M_2^{m_1} - 1 \qquad \text{(A2.4)}$$

Discrete times $t^n < t_o(m_1,m_2)$ are infeasible. Table 7.1(b) tabulates the average oil rate (Q_o) between cumulative oil intervals ($\Delta\mathcal{P}_1,\Delta\mathcal{P}_2$). The oil rate posted at each milestone is the average rate measured from the previous milestone.

$$Q_o(m_1,0) = \frac{[\mathcal{P}_1^{m_1} - \mathcal{P}_1^{m_1-1}]}{[t_o(m_1,0) - t_o(m_1-1,0)]} \quad ; m_1 = 1,2,\ldots,M_1 - 1$$

$$Q_o(m_1,m_2) = \frac{[\mathcal{P}_2^{m_2} - \mathcal{P}_2^{m_2-1}]}{[t_o(m_1,m_2) - t_o(m_1,m_2-1)]} \quad ; m_2 = 1,2,\ldots,M_2^{m_1} - 1 \qquad \text{(A2.5)}$$

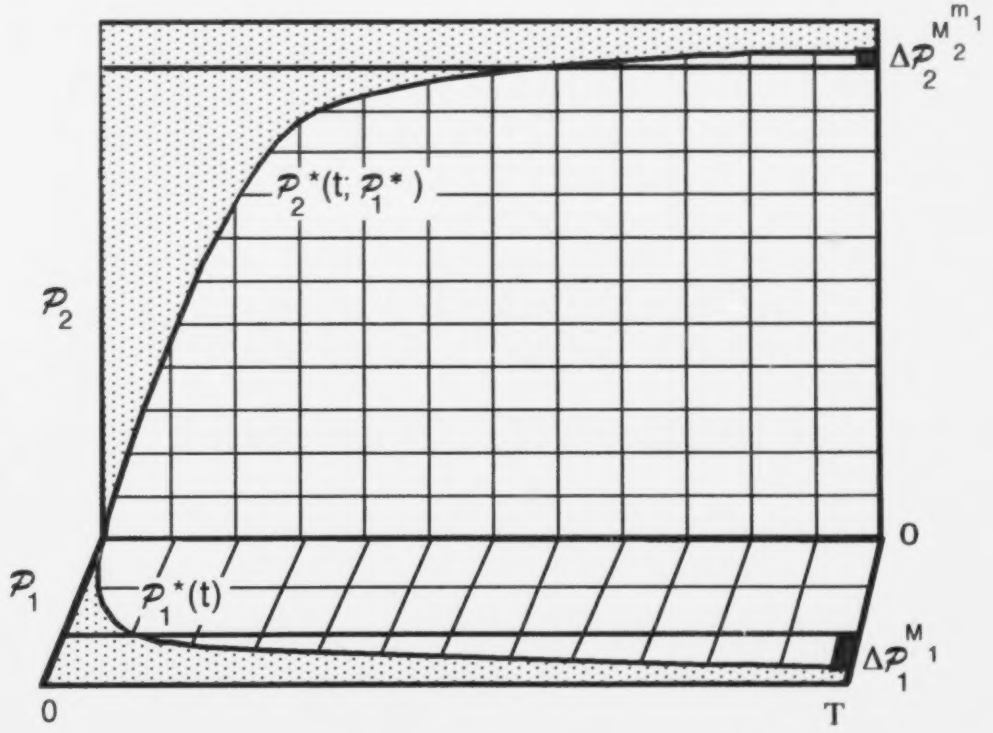
$\Delta\mathcal{P}_2^{M_2^{m_1}}$
$\mathcal{P}_2^*(t; \mathcal{P}_1^*)$
$\mathcal{P}_2$
0
$\mathcal{P}_1$
$\mathcal{P}_1^*(t)$
$\Delta\mathcal{P}_1^{M_1}$
0
T

Figure A2.4: Partial Intervals at Branch End-Points

The product of average rate at the branch endpoint and the time interval from the previous milestone gives the remaining cumulative oil recoverable along that branch. Partial intervals at branch endpoints are illustrated in Figure A2.4.

$$\Delta\mathcal{P}_1^{M_1} = Q_o(M_1,0)[t_o(M_1,0) - t_o(M_1-1,0)]$$

$$\Delta\mathcal{P}_2^{M_2^{m_1}} = Q_o(m_1, M_2^{m_1})\,[t_o(m_1, M_2^{m_1}) - t_o(m_1, M_2^{m_1}-1)] \qquad \text{(A2.6)}$$

A2.2 Sweep Direction

A forward pass with the black oil reservoir simulator forecasts future production possibilities in the depletion strategy. The contemporaneous reservoir state at each decision node depends on the sequence of past actions.

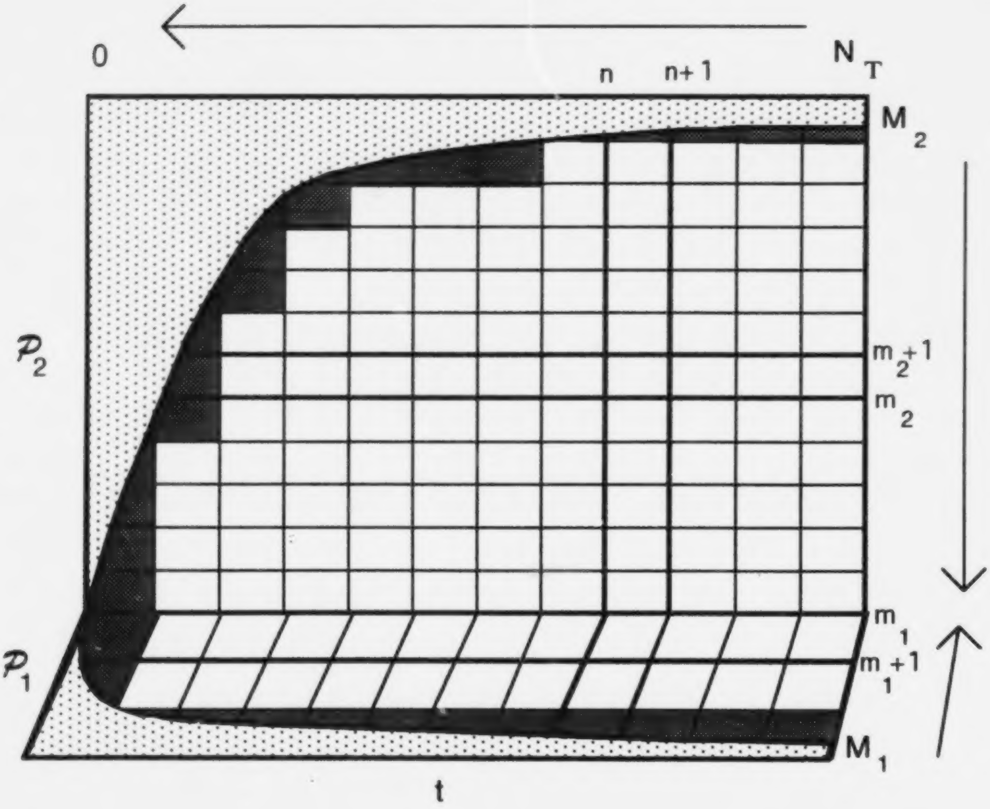

Figure A2.5: Backward Sweep Direction with Depletion Boundary Tracking

Dynamic programming is applied in a step-wise backward pass from terminal states to recursively find value-maximizing decision rules. The time step must be less than the minimum time interval between consecutive production milestones,

$$\Delta t < \min\{\Delta_1 t_o(m_1,0), \Delta_2 t_o(m_1,m_2);\ \text{over } (M_1 \times M_2)\} \tag{A2.7}$$

The depletion state difference operator along primary and secondary branches are defined by backward difference operators.

$$\begin{aligned} \Delta_1 t_o(m_1,0) &= t_o(m_1,0) - t_o(m_1-1,0) \\ \Delta_2 t_o(m_1,m_2) &= t_o(m_1,m_2) - t_o(m_1,m_2-1) \end{aligned} \tag{A2.8}$$

A2.3 Depletion Boundary Tracking

Contemporaneous branch endpoints are tracked on the stationary depletion grid (Figure A2.5). The nonstationary grid is represented by the internal depletion nodes on the regular stationary grid with an irregular moving endpoint at the feasible boundary. As time levels go back in time from t^{n+1} to t^n, the irregular endpoint interval shrinks until it crosses over to the next stationary depletion node. A tracking algorithm uses the $(M_1 \times M_2)$ cumulative production time $t_o(m_1,m_2)$ to determine the location of endpoints on the regular grid partition. Endpoints are bracketed by (M_1^n, M_1^{n+1}) for primary and $(M_2^{m_1,n}, M_2^{m_1,n+1})$ for secondary depletion boundaries (Figure A2.6).

$$\begin{aligned} t_o(M_1^n,0) \le\ & t^n < t_o(M_1^n+1,0) \\ t_o(M_1^{n+1},0) \le\ & t^{n+1} < t_o(M_1^{n+1}+1,0) \\ t_o(m_1,M_2^{m_1,n}) \le\ & t^n < t_o(m_1,M_2^{m_1,n}+1) \\ t_o(m_1,M_2^{m_1,n+1}) \le\ & t^{n+1} < t_o(m_1,M_2^{m_1,n+1}+1) \end{aligned} \tag{A2.9}$$

Time steps are chosen to ensure that discrete depletion milestones are not missed as the boundary path crosses over to the next stationary depletion node.

$$t^n \ge \max_{m_1}[t_o(M_1^n,0), t_o(m_1,M_2^{m_1,n})] \quad ; \ M_1^{n+1} - M_1^n \le 1 \ ; \ M_2^{m_1,n+1} - M_2^{m_1,n} \le 1 \tag{A2.10}$$

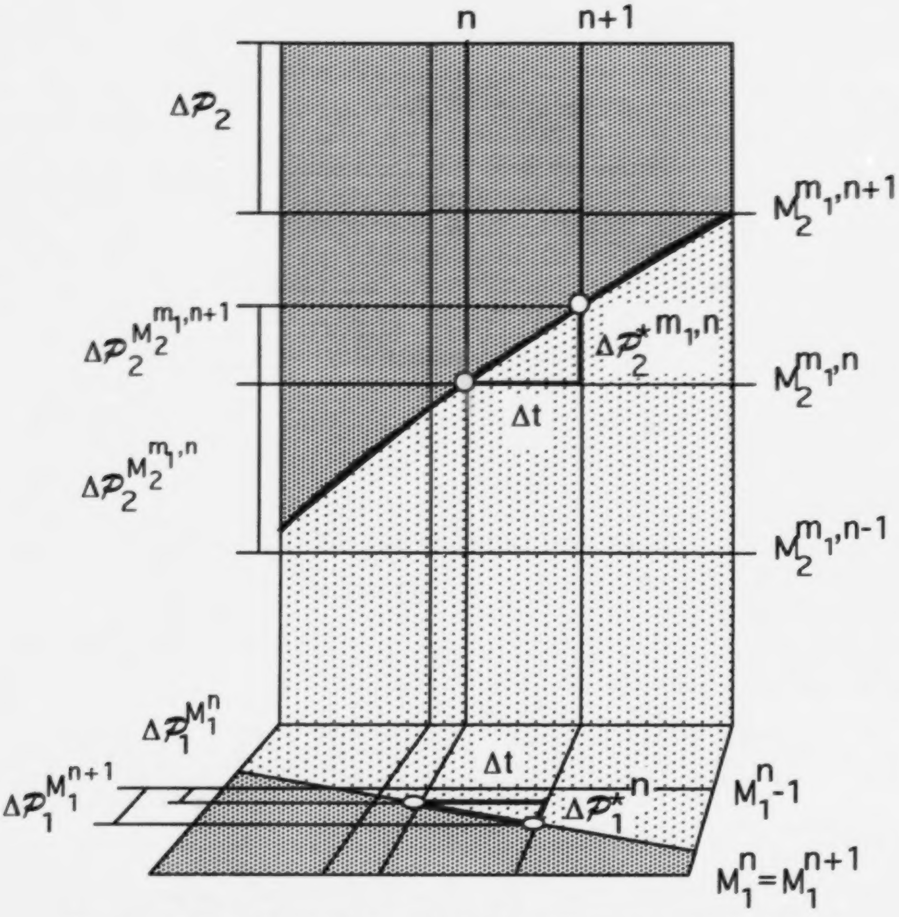
n
n+1
$\Delta\mathcal{P}_2$
$M_2^{m_1,n+1}$
$\Delta\mathcal{P}_2^{M_2^{m_1,n+1}}$
$\Delta\mathcal{P}_2^{*\,m_1,n}$
$M_2^{m_1,n}$
Δt
$\Delta\mathcal{P}_2^{M_2^{m_1,n}}$
$M_2^{m_1,n-1}$
$\Delta\mathcal{P}_1^{M_1^n}$
Δt
$\Delta\mathcal{P}_1^{M_1^{n+1}}$
n
$\Delta\mathcal{P}_1^*$
M_1^n-1
$M_1^n=M_1^{n+1}$

Figure A2.6: Boundary Bracketing and Incremental Tracking

Endpoint intervals are calculated using average oil production rates $Q_o(m_1,m_2)$ associated with the stationary grid.

$$\Delta\mathcal{P}_1^{M_1^n} = Q_o(M_1^n,0)\,[\,t^n - t_o(M_1^n - 1,0)]$$

$$\Delta\mathcal{P}_1^{M_1^{n+1}} = Q_o(M_1^{n+1},0)\,[\,t^{n+1} - t_o(M_1^{n+1} - 1,0)]$$

$$\Delta\mathcal{P}_2^{M_2^{m_1,n}} = Q_o(m_1,M_2^{m_1,n})\,[\,t^n - t_o(m_1,M_2^{m_1,n} - 1)]$$

$$\Delta\mathcal{P}_2^{M_2^{m_1,n+1}} = Q_o(m_1,M_2^{m_1,n+1})\,[\,t^{n+1} - t_o(m_1,M_2^{m_1,n+1} - 1)] \qquad \text{(A2.11)}$$

Incremental oil production along depletion boundaries ($\Delta\mathcal{P}_1^{*n}, \Delta\mathcal{P}_2^{*m_1,n}$) is calculated over the time step Δt.

$$\Delta\mathcal{P}_1^{*n} = \Delta\mathcal{P}_1^{M_1^{n+1}} - \Delta\mathcal{P}_1^{M_1^{n}} + \Delta\mathcal{P}_1(M_1^{n+1} - M_1^{n})$$

$$\Delta\mathcal{P}_2^{*m_1,n} = \Delta\mathcal{P}_2^{M_2^{m_1,n+1}} - \Delta\mathcal{P}_2^{M_2^{m_1,n}} + \Delta\mathcal{P}_2(M_2^{m_1,n+1} - M_2^{m_1,n}) \qquad \text{(A2.12)}$$

A2.4 Price-Time Grid Partition

Price is partitioned with regular and asymptotic price steps. Figure A2.7 shows the price-time grid partition. Discrete prices (s_i) are calculated over N_s=320 price steps. The price range between \$0-\$60/bbl is partitioned into $Ns_{regular}$=240 regular price steps (Δs=\$0.25/bbl).

$$s_i = i\,\Delta s \qquad i=0,1,\ldots,Ns_{regular} \qquad \text{(A2.13)}$$

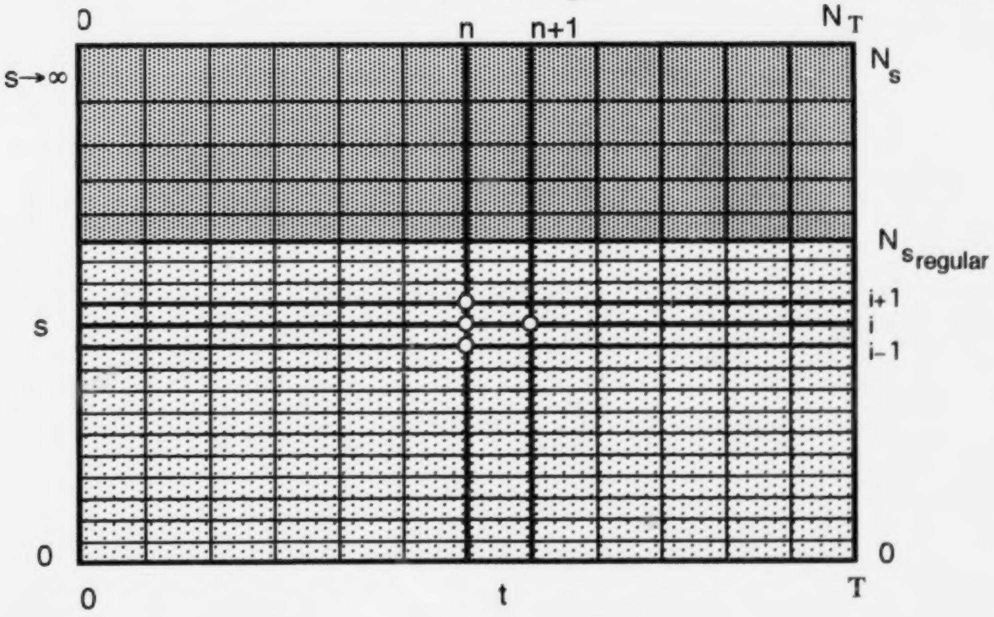

Figure A2.7: Price-Time (s,t) Grid with Regular and Asymptotic Steps

Asymptotic prices are calculated recursively using an expansion factor (=1.1),

$$s_{i+1} = 1.1\, s_i \qquad i=Ns_{regular}+1,\ldots,N_s \qquad \text{(A2.14)}$$

The maximum price state (s_{max}=\$122,904/bbl) approximates the limit ($s \rightarrow \infty$).

A2.5 Finite Differences

Primary and secondary values ($\mathcal{V}_1, \mathcal{V}_2$) are initialized to their corresponding terminal abandonment values over all price and depletion states at time $t^{N_T} = T$. Feasible depletion boundary endpoints are determined at the terminal time.

$$\begin{array}{ll}
\mathcal{V}_1^{N_T}(i,m_1) = -A_1 & ; i=0,1,\ldots,N_s ; m_1=0,1,\ldots,M_1^{N_T} \\
\mathcal{V}_2^{N_T}(i,m_1,m_2^{m_1}) = -A_2 & ; i=0,1,\ldots,N_s ; m_1=0,1,\ldots,M_1^{N_T} ; m_2^{m_1}=0,1,\ldots,M_2^{m_1,N_T}
\end{array}$$

(A2.15)

Operating modes (θ=C,S,A) are also initialized to their corresponding terminal abandonment values.

$$\begin{array}{ll}
\mathcal{V}_{1\theta}^{N_T}(i,m_1) = -A_1 & ; i=0,1,\ldots,N_s ; m_1=0,1,\ldots,M_1^{N_T} \\
\mathcal{V}_{2\theta}^{N_T}(i,m_1,m_2^{m_1}) = -A_2 & ; i=0,1,\ldots,N_s ; m_1=0,1,\ldots,M_1^{N_T} ; m_2^{m_1}=0,1,\ldots,M_2^{m_1,N_T}
\end{array}$$

(A2.16)

The terminal action for both primary and secondary operations (Θ_1, Θ_2) is the abandonment mode (θ=A).

$$\begin{array}{ll}
\Theta_1^{N_T}(i,m_1) = A & ; i=0,1,\ldots,N_s ; m_1=0,1,\ldots,M_1^{N_T} \\
\Theta_2^{N_T}(i,m_1,m_2^{m_1}) = A & ; i=0,1,\ldots,N_s ; m_1=0,1,\ldots,M_1^{N_T} ; m_2^{m_1}=0,1,\ldots,M_2^{m_1,N_T}
\end{array}$$

(A2.17)

Primary and secondary action-values are known at the future time level t^{n+1}. Feasible depletion boundary endpoints are determined for time level t^n. A primary loop sweeps from $m_1=M_1^n$ down to 0. Nested secondary loops sweep from $m_2=M_2^{m_1,n}$ down to 0.

Dynamic values for operating modes ($\mathcal{V}_{2C}, \mathcal{V}_{2S}$; $i=0,1,\ldots,N_s$) are determined sequentially for all feasible depletion states at time t^n. No production occurs in the suspended mode (θ_{2S}). Comparisons are made at each decision step between operating choices (θ_2=C,S,A), and the value-maximizing action selected. The maximum operation value $\mathcal{V}_2=\max(\mathcal{V}_{2C},\mathcal{V}_{2S},\mathcal{V}_{2A})$ then becomes the new basis for calculating dynamic operating values ($\mathcal{V}_{2C},\mathcal{V}_{2S}$) at the previous decision step. The differential equations in Eqns (8.38) and (8.39) are discretized at lattice points ($i,n,m_1,m_2^{m_1}$) using finite difference operators for price (Δ_s), time (Δ_t) and secondary depletion state (Δ_2).

$$\left[\begin{array}{c} \frac{1}{2}\sigma^2 s^2 \frac{\Delta_s^{\,2}\mathcal{V}_{2C}}{\Delta s^2} - (c-r)s\frac{\Delta_s \mathcal{V}_{2C}}{\Delta s} - r\mathcal{V}_{2C} + \mathcal{C}f_{2C} \\ + Q_{o_{2C}}\frac{\Delta_2 \mathcal{V}_{2C}}{\Delta \mathcal{P}_2} + \frac{\Delta_t \mathcal{V}_{2C}}{\Delta t} \end{array}\right]_i^{n,m_1,m_2} = 0$$

$$\left[\begin{array}{c} \frac{1}{2}\sigma^2 s^2 \frac{\Delta_s^{\,2}\mathcal{V}_{2S}}{\Delta s^2} - (c-r)s\frac{\Delta_s \mathcal{V}_{2S}}{\Delta s} - r\mathcal{V}_{2S} + \mathcal{C}f_{2S} \\ + \frac{\Delta_t \mathcal{V}_{2S}}{\Delta t} \end{array}\right]_i^{n,m_1,m_2} = 0 \qquad \text{(A2.18)}$$

Price differences (Δ_s) are calculated on a 3-point lattice (Figure A2.8). First order backward differences are chosen for stability.

$$\left.\frac{\Delta_s \mathcal{V}_{2\theta}}{\Delta s}\right|_i^{n,m_1,m_2} = \left[\frac{\mathcal{V}_{2\theta_i} - \mathcal{V}_{2\theta_{i-1}}}{s_i - s_{i-1}}\right]^{n,m_1,m_2}$$

$$\left.\frac{\Delta_s^2 \mathcal{V}_{2\theta}}{\Delta s^2}\right|_i^{n,m_1,m_2} = \frac{2}{s_{i+1} - s_{i-1}}\left[\frac{\mathcal{V}_{2\theta_{i+1}} - \mathcal{V}_{2\theta_i}}{s_{i+1} - s_i} - \frac{\mathcal{V}_{2\theta_i} - \mathcal{V}_{2\theta_{i-1}}}{s_i - s_{i-1}}\right]^{n,m_1,m_2} \qquad \text{(A2.19)}$$

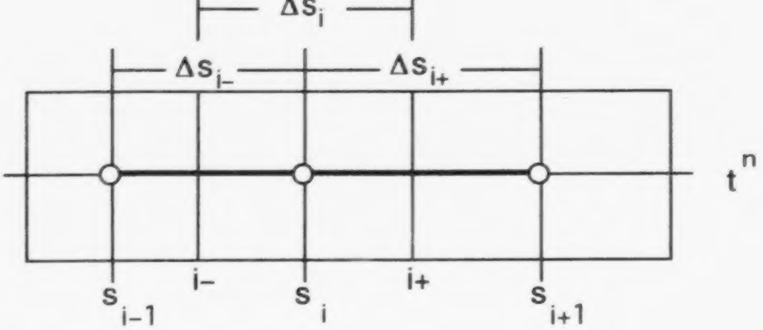
Δs_i
Δs_{i-}
Δs_{i+}
t^n
s_{i-1}
i–
s_i
i+
s_{i+1}

Figure A2.8: Price Difference Lattice

First and second-order price terms in Eqn. (A2.18) vanish at the price origin (i=0). The second order difference term vanishes at the asymptotic limit (i=N_s).

$$\left.\frac{\Delta_s^2 \mathcal{V}_{2\theta}}{\Delta s^2}\right|_{N_s}^{n,m_1,m_2} = 0 \tag{A2.20}$$

Forward differences are used for depletion paths.

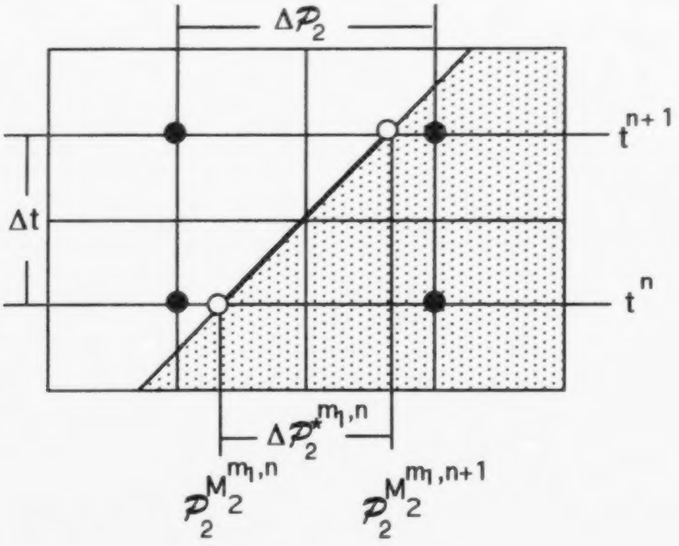
$\Delta\mathcal{P}_2$
t^{n+1}
Δt
t^n
$\Delta\mathcal{P}_2^{*m_1,n}$
$\mathcal{P}_2^{M_2^{m_1,n}}$
$\mathcal{P}_2^{M_2^{m_1,n+1}}$

Figure A2.9: Depletion Boundary Difference Lattice

Difference operations on internal stationary lattice points are handled differently from nonstationary depletion boundary points. Depletion paths can either have positive slopes with increasing cumulative production along actively controlled segments or remain constant along suspended path segments. Actively controlled production value along the depletion boundary is first calculated at $M_2^{m_1,n}$ from known values at $M_2^{m_1,n+1}$. The combined partial derivatives with respect to time and depletion state reduce to the time derivative along the boundary depletion path (Figure A2.9).

$$\left[Q_{o_{2C}} \frac{\Delta_2 \mathcal{V}_{2C}}{\Delta \mathcal{P}_2} + \frac{\Delta_t \mathcal{V}_{2C}}{\Delta t} \right]_i^{n,m_1,M_2^{n,m_1}} = \left[\frac{\Delta \mathcal{P}^*_2}{\Delta t} \frac{\Delta^*_2 \mathcal{V}_{2C}}{\Delta \mathcal{P}^*_2} \right]_i^{n,m_1,M_2^{n,m_1}}$$

$$= \left[\frac{\mathcal{V}_{2C}^{n+1,m_1,M_2^{n+1,m_1}} - \mathcal{V}_{2C}^{n,m_1,M_2^{n,m_1}}}{t^{n+1} - t^n} \right]_i \tag{A2.21}$$

A simplifying assumption is used to approximate time differences for suspended production value at the feasible boundary.

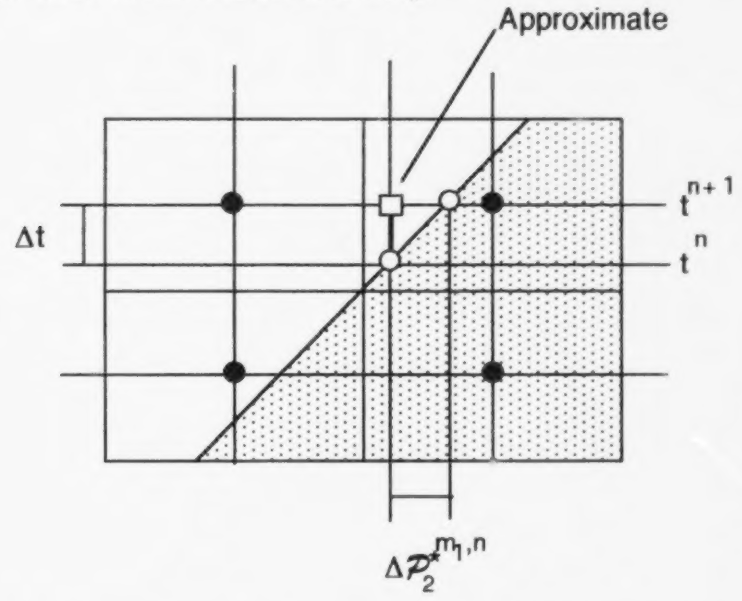

Figure A2.10: Suspended Depletion Boundary Value Time Difference

Boundary nodes $M_2^{m_1,n}$ that do not coincide with the discrete depletion partition must either use interpolated values at t^{n+1} or have an intermediate depletion partition that coincides with $M_2^{m_1,n}$ (Figure A2.10). An intermediate depletion partition would need to run from the terminal time to the contemporaneous calculation node. The need for additional partitions will grow rapidly with the incremental changes in depletion boundary. The partition needed to resolve the suspended production value over all depletion boundaries will be in the order of the total time steps. This high resolution approach is computationally prohibitive with memory requirements being several orders of magnitude larger than the present partition. Furthermore, the finer partition demands more secondary branch forecasts along transitional primary depletion states. The computational algorithm described here adopts a simplifying approximation for suspended production value along the depletion boundary. Linear interpolation between adjacent nodes on the same depletion line is not used since irreversible actions at previous depletion states may divert the decision process along other pathways. One choice is to approximate the transient changes in suspended production value forward along the actively controlled depletion boundary. If time steps are selected small enough, the error in the zero-order approximation will be bounded.

$$\left[\frac{\Delta_t \mathcal{V}_{2S}}{\Delta t}\right]_i^{n,m_1,M_2^{n,m_1}} = \left[\frac{\mathcal{V}_{2S}^{n+1,m_1,M_2^{n+1,m_1}} - \mathcal{V}_{2S}^{n,m_1,M_2^{n,m_1}}}{t^{n+1} - t^n}\right]_i \tag{A2.22}$$

A non-stationary 3-point difference lattice is used for boundary adjacent depletion grid points (Figure A2.11). Depletion state difference operators at time t^n are calculated on the basis of forward values along depletion paths at t^{n+1}.

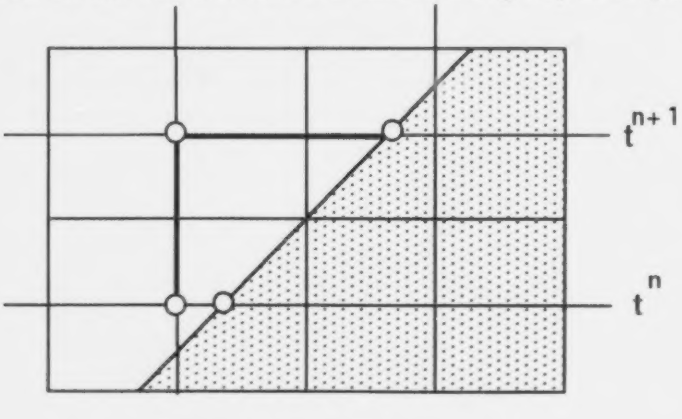

Figure A2.11: Non-Stationary Depletion State Difference Lattice

$$\left.\frac{\Delta_t \mathcal{V}_{2\theta}}{\Delta t}\right|_i^{n,m_1,M_2^{n,m_1}-1} = \left[\frac{\mathcal{V}_{2\theta}^{n+1} - \mathcal{V}_{2\theta}^{n}}{t^{n+1} - t^{n}}\right]_i^{m_1,M_2^{n,m_1}-1}$$

$$\left.\frac{\Delta_2 \mathcal{V}_{2C}}{\Delta \mathcal{P}_2}\right|_i^{n,m_1,M_2^{n,m_1}-1} = \left[\frac{\mathcal{V}_{2C}^{M_2^{n+1,m_1}} - \mathcal{V}_{2C}^{M_2^{n+1,m_1}-1}}{\mathcal{P}_2^{M_2^{n,m_1}} - \mathcal{P}_2^{M_2^{n,m_1}-1}}\right]_i^{n+1,m_1} \tag{A2.23}$$

A stationary 3-point difference lattice is used for internal depletion grid points (Figure A2.12).

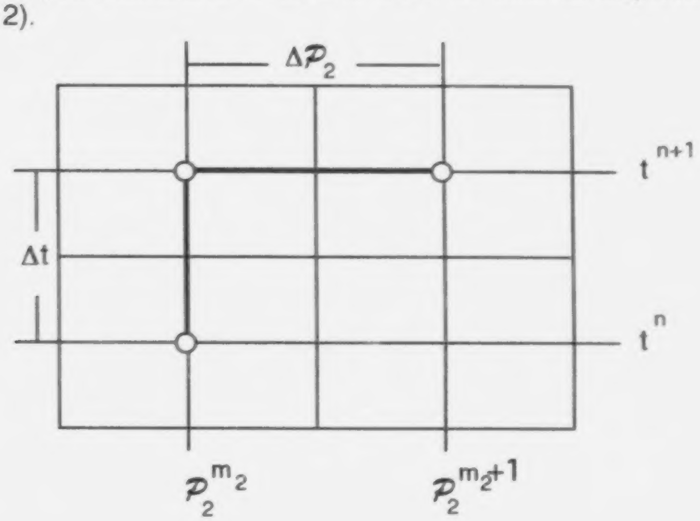

Figure A2.12: Stationary Depletion Difference Lattice

$$\left.\frac{\Delta_t \mathcal{V}_{2\theta}}{\Delta t}\right|_i^{n,m_1,m_2} = \left[\frac{\mathcal{V}_{2\theta}^{n+1} - \mathcal{V}_{2\theta}^{n}}{t^{n+1} - t^{n}}\right]_i^{m_1,m_2}$$

$$\left.\frac{\Delta_2 \mathcal{V}_{2C}}{\Delta \mathcal{P}_2}\right|_i^{n,m_1,m_2} = \left[\frac{\mathcal{V}_{2C}^{m_2+1} - \mathcal{V}_{2C}^{m_2}}{\mathcal{P}_2^{m_2+1} - \mathcal{P}_2^{m_2}}\right]_i^{n+1,m_1} \tag{A2.24}$$

Independent finite-difference equations for ($\mathcal{V}_{2C}$,$\mathcal{V}_{2S}$) are solved implicitly for all price states at (n,m_1,$m_2^{m_1}$) using a tri-diagonal algorithm.

$$\begin{aligned} A_{2C_i}\mathcal{V}_{2C_{i-1}}^{n,m_1,m_2} + B_{2C_i}\mathcal{V}_{2C_i}^{n,m_1,m_2} + C_{2C_i}\mathcal{V}_{2C_{i+1}}^{n,m_1,m_2} &= D_{2C_i} \\ A_{2S_i}\mathcal{V}_{2S_{i-1}}^{n,m_1,m_2} + B_{2S_i}\mathcal{V}_{2S_i}^{n,m_1,m_2} + C_{2S_i}\mathcal{V}_{2S_{i+1}}^{n,m_1,m_2} &= D_{2S_i} \end{aligned} \tag{A2.25}$$

Value-maximizing actions for secondary operations $\mathcal{V}_2=\max(\mathcal{V}_{2C},\mathcal{V}_{2S},\mathcal{V}_{2A})$ are determined at each price state (i).

$$\left.\begin{aligned} \mathcal{V}_2^n(i,m_1,m_2^{m_1}) &= \max\{\mathcal{V}_{2C}^n(i,m_1,m_2^{m_1}),\mathcal{V}_{2S}^n(i,m_1,m_2^{m_1}),-A_2\} \\ \Theta_2^n(i,m_1,m_2^{m_1}) &= C \quad \text{if } \mathcal{V}_2^n(i,m_1,m_2^{m_1})=\mathcal{V}_{2C}^n(i,m_1,m_2^{m_1}) \\ &= S \quad \text{if } \mathcal{V}_2^n(i,m_1,m_2^{m_1})=\mathcal{V}_{2S}^n(i,m_1,m_2^{m_1}) \\ &= A \quad \text{if } \mathcal{V}_2^n(i,m_1,m_2^{m_1})=-A_2 \end{aligned}\right] ; i=0,1,\ldots,N_s \tag{A2.26}$$

Secondary operation values are calculated over all price states $(i=0,1,\ldots,N_s)$ for feasible secondary depletion states $(m_2=0,1,\ldots,M_2^{n,m_1})$ from feasible primary depletion states $(m_1=0,1,\ldots,M_1^n)$ at the contemporaneous time level (t^n) from pre-established secondary values $(\mathcal{V}_2)$ at the future time level (t^{n+1}).

```
For $m_1 = M_1^n,\ldots,1,0$
 For $m_2^{m_1} = M_2^{n,m_1},\ldots,1,0$
  Solve $\{\mathcal{V}_{2C}^n(i,m_1,m_2^{m_1}),\mathcal{V}_{2S}^n(i,m_1,m_2^{m_1}); i=0,1,\ldots,N_s\}$
  $\mathcal{V}_2^n(i,m_1,m_2^{m_1}) = \max\{\mathcal{V}_{2C}^n(i,m_1,m_2^{m_1}),\mathcal{V}_{2S}^n(i,m_1,m_2^{m_1}),-A_2\}$  ] $i=0,1,\ldots,N_s$
  Map Actions: $\Theta_2^n(i,m_1,m_2^{m_1}) = (C,S,A)$                                                  ]
 Next $m_2^{m_1}$
Next $m_1$
```

The backward sweep direction ensures that unknown values can be determined from pre-calculated values. The maximized secondary value at the contemporaneous decision step becomes the new basis for calculating dynamic operating values $(\mathcal{V}_{2C},\mathcal{V}_{2S})^{n+1}=\mathcal{V}_2^{\,n}$ at the previous decision step.

Similarly, dynamic values for primary operating modes $(\mathcal{V}_{1C},\mathcal{V}_{1S};i=0,1,\ldots,N_s)$ are determined sequentially for all feasible depletion states at time t^n. No production occurs in the suspended mode (θ_{1S}). Comparisons are made at each decision step between operating choices $(\theta_1=C,S,A)$ and the value-maximizing action selected $\mathcal{V}_1=\max(\mathcal{V}_{1C},\mathcal{V}_{1S},\mathcal{V}_{1A})$. The remaining primary operation value is then compared with the initiating waterflood value net of capital investment, $\mathcal{V}=\max(\mathcal{V}_1,\mathcal{V}_2-K_{12})$. The maximized value at the contemporaneous decision step becomes the new basis for calculating dynamic operating values $(\mathcal{V}_{1C},\mathcal{V}_{1S})^{n+1}=\mathcal{V}^{\,n}$ at the previous decision step. The differential equations are discretized at lattice points (i,n,m_1) using finite difference operators for price (Δ_s), time (Δ_t) and primary depletion state (Δ_1).

$$\left[\begin{array}{c}\frac{1}{2}\sigma^2 s^2\frac{\Delta_s^{\,2}\mathcal{V}_{1C}}{\Delta s^2} - (c-r)s\frac{\Delta_s\mathcal{V}_{1C}}{\Delta s} - r\mathcal{V}_{1C} + \mathcal{C}f_{1C} \\ + Q_{o_{1C}}\frac{\Delta_1\mathcal{V}_{1C}}{\Delta\mathcal{P}_1} + \frac{\Delta_t\mathcal{V}_{1C}}{\Delta t}\end{array}\right]_i^{n,m_1} = 0$$

$$\left[\begin{array}{c}\frac{1}{2}\sigma^2 s^2\frac{\Delta_s^{\,2}\mathcal{V}_{1S}}{\Delta s^2} - (c-r)s\frac{\Delta_s\mathcal{V}_{1S}}{\Delta s} - r\mathcal{V}_{1S} + \mathcal{C}f_{1S} \\ + \frac{\Delta_t\mathcal{V}_{1S}}{\Delta t}\end{array}\right]_i^{n,m_1} = 0 \qquad \text{(A2.27)}$$

Independent finite-difference equations for $(\mathcal{V}_{1C},\mathcal{V}_{1S})$ are found in the same manner as described for secondary operations. These are solved implicitly for all price states at (n,m_1) using a tri-diagonal algorithm.

$$A_{1C_i}\mathcal{V}_{1C_{i-1}}^{n,m_1} + B_{1C_i}\mathcal{V}_{1C_i}^{n,m_1} + C_{1C_i}\mathcal{V}_{1C_{i+1}}^{n,m_1} = D_{1C_i}$$

$$A_{1S_i}\mathcal{V}_{1S_{i-1}}^{n,m_1} + B_{1S_i}\mathcal{V}_{1S_i}^{n,m_1} + C_{1S_i}\mathcal{V}_{1S_{i+1}}^{n,m_1} = D_{1S_i} \qquad \text{(A2.28)}$$

Value-maximizing primary actions are determined at each price state (i).

$$\left.\begin{aligned}
\mathcal{V}_1^n(i,m_1) &= \max\{\mathcal{V}_{1C}^n(i,m_1),\mathcal{V}_{1S}^n(i,m_1),-A_1\}\\
\Theta_1^n(i,m_1) &= C \quad \text{if} \quad \mathcal{V}_1^n(i,m_1)=\mathcal{V}_{1C}^n(i,m_1)\\
&= S \quad \text{if} \quad \mathcal{V}_1^n(i,m_1)=\mathcal{V}_{1S}^n(i,m_1)\\
&= A \quad \text{if} \quad \mathcal{V}_1^n(i,m_1)=-A_1
\end{aligned}\right];i=0,1,\ldots,N_s \tag{A2.29}$$

Secondary values, net of capital investment at waterflood initiation states (m_2=0), are compared with primary operating values at all primary states (m_1=0,1,...,M_1^n).

$$\left.\begin{aligned}
\mathcal{V}^n(i,m_1) &= \max\{\mathcal{V}_2^n(i,m_1,0)-K_{12},\mathcal{V}_1^n(i,m_1)\\
\mathcal{D}^n(i,m_1) &= \Theta_1^n \quad \text{if} \quad \mathcal{V}^n(i,m_1)=\mathcal{V}_1^n(i,m_1)\\
&= \Theta_2^n \quad \text{if} \quad \mathcal{V}^n(i,m_1)=\mathcal{V}_2^n(i,m_1,0)-K_{12}
\end{aligned}\right];i=0,1,\ldots,N_s \tag{A2.30}$$

Remaining depletion strategy values are calculated over all price states (i=0,1,...,N_s) for feasible primary depletion states (m_1=0,1,...,M_1^n) at the contemporaneous time level (t^n) from pre-established primary values ($\mathcal{V}$) at the future time level (t^{n+1}).

```
For $m_1 = M_1^n,\ldots,1,0$
  Solve $\{\mathcal{V}_{1C}^n(i,m_1),\mathcal{V}_{1S}^n(i,m_1); i=0,1,\ldots,N_s\}$
  $\mathcal{V}_1^n(i,m_1) = \max\{\mathcal{V}_{1C}^n(i,m_1),\mathcal{V}_{1S}^n(i,m_1),-A_1\}$   ] $i=0,1,\ldots,N_s$
  Map Actions: $\Theta_1^n(i,m_1) = (C,S,A)$                                                  ]
  $\mathcal{V}^n(i,m_1) = \max\{\mathcal{V}_2^n(i,m_1,0)-K_{12},\mathcal{V}_1^n(i,m_1)\}$   ] $i=0,1,\ldots,N_s$
  Map Actions: $\mathcal{D}^n(i,m_1) = (\Theta_1^n,\Theta_2^n)$                              ]
Next $m_1$
```